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PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Distributed Generation in Hawaii.	DOCKET NO. 03-0371

COUNTY OF MAUI'S RESPONSES TO INFORMATION REQUESTS FROM HECO/HELCO/MECO, THE CONSUMER ADVOCATE, THE HAWAII RENEWABLE ENERGY ALLIANCE, LIFE OF THE LAND, AND HESS MICROGEN

CERTIFICATE OF SERVICE

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RESPONSES TO HECO/HELCO/MECO

HECO/Maui-DT-IR-1 Ref: COM-T-1, Page 19, Lines 12-14

a. Please identify any electric utilities that "aggregate networks of customer-sited generators together into "virtual power plants" to provide grid reliability services"?

RESPONSE: Public Service of New Mexico.

b. For any utilities provided in response to part a. above, please provide a website or contact information for the virtual power plant department, and detailed information on the capital and operating and maintenance costs for the "virtual power plants".

RESPONSE: See the attached case study (eight pages).

Distributed Generation: A Case Study

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Abstract

With the impending cloud of deregulation on the horizon, discussions within the power industry have increasingly focussed on alternative means of providing consumers with energy services. The days of demonstrating need, lobbying for money, and then building new infrastructure are fading. Return on investments will have to be justified from competitive sales of energy and services, and not from approved rate increases. As a result distributed generation (DG) has become a hot topic. Like any other tonic of the day, DG is sold as an immediate cure all for all constraints. But, few distributed generation systems have been implemented as an integrated part of a utility distribution system.

The reasons for this slow motion in the utility industry are not only an inherent inertia within the industry, but also a failure to justify the cost of the systems. Much of the discussion of distributed generation has dealt primarily with new and emerging technologies. The challenge with focussing on technologies such as microturbines and fuel cells is that not only does the new technology have to be perfected and made cost effective, but the infrastructure to support the distributed generation still has to be added within the utility. What has been overlooked is the installed capacity of standby generation, and the relatively small cost of transitioning these seldom used resources to useful purposes.

Utilities currently use some of the installed capacity of standby generation indirectly by providing interruptible rates. These rates allow the customer to evaluate the value of utility power, and allow its service to be interrupted on demand from the utility. Many of these customers have installed standby generation and allow their systems to experience a temporary outage while their onsite generation comes on line. The outage time is often mitigated by taking advantage of the utility's short notice, 1, 10, or 30 minutes, and ensuring that the local generation is available prior to removal of service by the utility. The longer the time before interruption, the smaller the value is to the utility and the lower the reward. Regardless, the customer experiences a degree of voltage and frequency transient.

Background:

Before looking in detail at the cost of using standby generation as a peaking resource, it is important to frame the discussion. The most customer friendly method of implementing such a system is "Peak Sharing". The word share is used intentionally as opposed to "Peak Shaving", because the system results in a cooperative effort between the utility and the customer to reduce the system-wide peak demand and at the same time provide cost effective power.

Some of the benefits of "Peak Sharing" to the utility are:

- Dispatchable peak demand reduction

- Maximum use of standby capacity through safe parallel operation with the utility grid
- Cost-effective solution consistent with least cost planning emphasis
- Improved system load factor
- Enhanced voltage stability and avoided line losses during heavy-load conditions
- Improved customer relations

One of the key points here is the last; improved customer relations. As mentioned earlier, many standby generator sets are used as demand side management by the utility through interruptible rates. These systems are often not crafted with the customer in mind. An example is one of the newspapers in Northern Colorado. The paper subscribes to the local utility's interruptible rate in order to lower their electric bill. The system employed at the customer site is an open transition manual transfer switch with a standby generator as the emergency source. The building experiences a loss of power until an operator can switch manually switch sources.

To reduce problems with the power interruption, the paper has assigned a person whose job is to watch for the signal from the utility. The paper gets a one minute prior notice that lights a red light. The employee then runs across the room to start the generator before the normal source is de-energized. This method ensures the generator is up to speed prior to the interrupt signal being sent by the utility. This is a customer who will entertain different providers of electricity when deregulation arrives.

Some benefits of "Peak Sharing" to the customer are:

- Utility customers save on electricity costs by turning idle standby generators into revenue-producing assets
- Standby generators are tested under real-life conditions with "blipless" power transfers
- If continuous parallel is allowed the customer gets a more reliable source of power

In a regulated system customer satisfaction is not a paramount issue. In a competitive environment a happy customer is a customer. An unhappy customer is someone else's customer.

Distributed Generation System

One of the keys to a successful distributed generation system is to design it with the utility or energy service company (ESCO) in mind. There are basically four aspects to a system which enable a utility or ESCO to absorb it into their normal operations.

First, and foremost are the dispatch screens or user interface. When reserve margins begin to get low, control centers at utilities are hectic environments. When a dispatcher is in a critical period, he/she wants a very simple interface. The system needs to be as simple as, press this button and get this amount of demand reduction. After pressing the button the dispatcher does not want to be bothered further other than to see how much actual reduction was achieved. If there is not a simple front end, the system will not gain acceptance.

During off periods the dispatcher needs to be given greater flexibility to group resources for optimization purposes. Resources can be grouped by resulting pollution, cost, or grid location.

Secondly, the system must be open to allow intelligent and automatic dispatch of resources. Most utilities have installed vast SCADA systems which provide data on a myriad of different parameters throughout their grid. The distributed generation system needs to be flexible enough to interface with existing systems.

> As an example, if a utility received real time load factor data from its substations, it might desire to automatically dispatch generation resources downstream of a particular substation whenever the load factor exceeds a predetermined level.

Thirdly, the system must handle monetary data collection. If the customer is signed up to provide 1.0 MW of power on demand with a 1 minute notice, then this performance needs to be verified. Even more important, if the system is saving the customer money, it is vital to present this information along with the customer's monthly bill. Again, as in the automatic control scenario, it is imperative that any installed system have an open database structure to allow collected information to be utilized within the utility's existing accounting and billing system.

Finally, the system needs to provide a means for preventative maintenance and tracking of the generator set usage. If it is designed to rapidly dispatch and record data from the generator and the site itself, then collecting preventative maintenance data is a desirable bonus feature. Most commercial and many industrial sites do not have a keen interest in self-maintenance of their generator sets. It is rarely their core business. As a result, it is desirable to provide an outside entity with the ability to load test and monitor the generator remotely.

> A typical Caterpillar dealer will offer a complete maintenance package on a three to five year contract that covers all preventative maintenance and an extended warranty for approximately $4800 annually for a 1000 kW set. This includes oil changes, lubrication, inspection, battery checks, protective relay cycling, cooling system maintenance, etc.

The cost of maintenance is reduced when the service company can accurately predict failures and the need for maintenance. Remote monitoring also ensures that the truly talented mechanics and technicians spend their valuable time trouble shooting only difficult problems.

Case Study

As a case study for the applicability of distributed generation using currently installed assets; Albuquerque is a good example. It is a typical city in the Western U.S. It has been growing at a steady rate.

> From 1992 to 1993, total personal income was up 7.5 percent in New Mexico, while per capita personal income increased 5.2 percent. Between March 1994 and March 1995, employment in Albuquerque metropolitan area increased 6.5 percent, unemployment was down 15.2 percent, and the total civilian labor force increased 5.4 percent.

With continual growth in the economy, the demand on the local utility, Public Service of New Mexico (PNM), has increased proportionally.

> Demand for electricity has grown at a steady 4% annually throughout the nineties. The total yearly consumption of electricity increased 20% from 1989 to 1994, and the system peak rose from 1.006 GW in 1989 to 1.247 GW in 1995, a rise of nearly 25%.

As a result, and in order to meet increased peak demand, the utility tried for years to bring in additional power by running a new transmission line to the city. Continuing problems with siting the transmission line lead this idea to be abandoned. The utility then decided that the building of a 100 MW natural gas-fired peaking unit would be the near term solution for the 60 or so hours a year during the summer when additional power was required. This 30 minute dispatchable peaking unit is scheduled to be on line in May of 1999. The utility has put off consideration of any new transmission lines until the uncertainty deregulation brings passes.

> Public Service of New Mexico, Enron Corporation, and the New Mexico Retail Association have jointly proposed to the New Mexico Public Utility Commission a plan for restructuring of the electric industry that calls for open access on 1/1/2001

As a result, PNM is also looking at different rate structures under the current regulated market to bring more distributed generation assets under their control.

Cost of site installation

The site that will be used for cost analysis consists of three generator sets: two 450 kW Cummins units and an 800 kW Waukesha set. The total site generation is 1700kW. It has an ASCO switchgear setup that consists of a

480 V cabinet with an electrically operated breaker for each generator and one for the tie to the utility. The system is set up as standby power. It senses loss of the utility source, starts the generators, disconnects from the utility, parallels the generators to the bus, and loads them. This functionality must be maintained throughout and after the upgrade to ensure reliable power. The site is a hospital. The estimated costs are as follows:

Note: The attached figure shows the basic equipment required at a DG customer site

Item	Cost per unit	Quantity	Total
Generator Set Controls	$6,500.00	3	$19,500
Master Control	$8,000.00	1	$8000.00
Connectivity (Relays and disconnect)	$6,000.00	1	$6,000.00
Interconnection costs	$2,500.00	1	$2,500.00
Site review, documentation, installation and test	$46,200.00	1	$46,200.00
Total			$82,200.00

The generator sets controls are being upgraded to fully programmable digital controls that seamlessly interface with the master control to allow complete monitoring of electrical parameters associated with the site and control of all of site generation as a bank.

The $82,200 price tag translates to a cost of $48.35/kW. The total capacity of generation at a site is not 100% available at all times, and if a zero power transfer between the site and the utility is enforced, the net available capacity is never greater than the instantaneous demand of the site. As a result a 70% availability factor is used to rate the site at 1190 kW for a resulting cost of $69.07/kW. This is a very attractive price to bring additional generation on line. A ballpark figure of $300/kW is often quoted for transmission and distribution expansion. This number is subject to the geography of the region in question and varies from as low as $100/kW to well over $1000/kW for underground lines through cities. In any case, the resulting cost of this site is less than $100/kW.

The site cataloged above has currently installed switchgear. Not all sites will be of this sort. It is useful to look at the additional costs if switchgear had to be added. This is detailed below

Item	Cost per unit	Quantity	Total
Generator Set Panels	$16,000.00	3	$48,000.00
Master Control Panel	$30,000.00	1	$30,000.00
Additional installation	$25,000.00	1	$25,000.00

If switchgear had to be added the cost would then be estimated at $185,200.00 or $108.94/kW. Again using an

If switchgear had to be added the cost would then be estimated at $185,200.00 or $108.94/kW. Again using an availability factor of 70% yields $155.63/kW. This number is still competitive with all but the least expensive T&D scenarios.

In fairness, the costs presented so far have been solely the site costs and have not dealt with the cost to the utility in adding a system to manage distributed generation resources. The table below lists approximate cost of implementing a basic integrated DG system:

Item	**Cost**
High Speed NT Workstation	$5,000.00
Peripherals (modems, routers, etc)	$2,000.00
Software License	$15,000.00
Installations costs	$5,000.00
Total	$27,000.00

The prices listed above are based on an installation that will simply handle the first site. Additional sites can be added for an approximate incremental cost of $2000.00 per site. If the $27,000.00 figure is used and costed against the site detailed above, the total cost of the first site becomes $109,000 or $91.60/kW adjusted for the 70% utilization. With the addition of switchgear this number would be $212,000.00 or $178.31/kW.

Example Rate Case

The initial thought by Public Service of New Mexico has been to get the customer to outlay the cost of the site upgrade by offering a demand reduction rebate. The table below shows the proposed rates in dollars per kW-month.

Note: these rates have not been approved, and at the time of writing were on hold

1 Hour Peak	**1 Hour Mid-Peak**	**Inst. Peak**	**Inst. Mid-Peak**
$17.52	$6.44	$24.75	$9.09
$15.36	$5.64	$21.69	$7.69
$8.67	$3.18	$12.24	$4.49
$16.91	$6.21	$23.89	$8.78

Times listed are for dispatch response time. Instantaneous is defined as controlled by the utility with no notice given to the customer of dispatch. The system detailed above falls into the instantaneous category. Peak is defined as June through August, 1:00 PM to 6:00PM, M-F. Mid-Peak is defined as June through August, 8:00 AM to 1:00 PM and 6:00 PM to 10:00 PM, M-F. The rates apply to different customer classifications and are not detailed in this paper.

The candidates for this rate would be customers within the Albuquerque area with the ability to mitigate at least 200 kW during the defined peak periods. The available rebate is to be calculated as follows:

> The customer would sign a contract defining a Fixed Capacity at which they would guarantee the ability to operate at or below upon the dispatch signal from the utility. The rebate would then be based on the customer's maximum peak demand minus the fixed capacity for the two periods individually multiplied by the rates cataloged above.

Based upon this we can review two scenarios:

Scenario #1

1. If the following assumptions are used:
2. The fuel cost of diesel will be $0.05/kWh
3. The fixed maintenance cost will be set at $8500 per year ($5.00/kW)
4. A variable operations and maintenance cost associated with wear and tear will be set at $0.10/kWh
5. Only the rebate during the peak period will be included
6. The assumed mitigated load (peak demand fixed capacity) will be 500kW (less than one third of the available capacity)
7. The dispatch time will be set at 20 hours per month

Based on these assumptions the rebate for each month would be the rate, $24.75/kW-month for this site, times the mitigated load, 500 kW, less the expenses.

The gross rebate is then $12,375 per month. Expenses due to fuel would be $500.00 and the variable O&M would come to $1000.00. This yields a monthly total before yearly maintenance costs of $10,875, or a three-month total of $32,625. Subtracting the maintenance fee yields a net yearly savings of $24,125 for this site. The payback for the site equipment and dispatch system combined would then take four years.

These numbers are overly conservative. The fixed maintenance cost would be incurred whether the generators participate in the program or not. It is a cost the hospital pays to ensure reliable power, and is normally viewed simply as an unavoidable cost of doing business. Furthermore, even assuming the failure of one generator at all times, the site would be able to mitigate at least 1.0 MW below its peak demand. If the scenario is changed to the following:

Scenario #2

1. The fuel cost of diesel will be $0.05/kWh
2. The fixed maintenance cost is not included because it would be incurred regardless of participation
3. A variable operations and maintenance will be ignored because typical maintenance contracts charge a fixed fee for 0 300 hours of run time per year
4. Only the rebate during the peak period will be included
5. The assumed mitigated load (peak demand fixed capacity) will be 1000kW (58.8% of the available capacity)
6. The dispatch time will be set at 20 hours per month

Based on these assumptions the rebate for each month would be the rate, $24.75/kW-month for this site, times the mitigated load, 1000 kW, less the expenses.

The gross rebate is then $24,750 per month. Expenses due to fuel would be $1000.00. This yields a monthly net of $23,750, or a three-month total of $71,150. The payback for the site equipment and dispatch system combined would then take four summer months or one year and one summer month.

As one might expect from the calculation of these numbers, the customer in question is anxious to have the rate approved and to sign up.

Utility Benefits

The above scenarios present a clear case as to why a customer like this would sign up for the program, but what is in it for the utility? The rate program has essentially four goals:

1. Bring generating assets into PNM's control at smaller increments than the 100 MW peaking unit currently being built. This allows the utility to compete effectively even after its wire charges for stranded assets expire. New Mexico is currently scheduled to go into full deregulation on January 1, 2001. PNM has proposed a 15-year payback from that date on its stranded assets.
2. Allow PNM to gain access to generation resources which do not have a 25-year pay back and are flexible in the face of future market changes. The uncertainty of the future market does not lend itself well to the traditional 20 to 30 year return on investment schemes. The commitment to this program can be broken into three or five-year contracts and renegotiated based on actual value.
3. To forge better relationships with key customers, and to put up barriers of satisfied customers to the energy service companies that will come prospecting for business after deregulation.
4. Test new methods for producing cost effective power and services so that it can compete in other utility's territories after deregulation.

PNM, being a combined gas and electric utility, is learning the hard lessons of the open market on its gas side of the business. ENRON and Industrial Gas Sales, Inc are already in direct competition with PNM for residential, commercial, and industrial gas customers.

Why not sooner?

Utilities have implemented Herculean efforts to become more customer orientated. Yet, the fact remains that a company cannot become customer orientated in a way the rest of industry would until their very survival is on the line. Without the daily feedback of customers leaving for other providers it is difficult for a corporation to hone their customer skills. In fact, every day large corporations go out and buy business in order to meet strategic and market share goals. A utility's customers have been captive. Utilities have assigned different sales support people to particular applications. Residential and commercial customers, hospitals, and industries have all been broken out for special attention, but the general operation of the company as a whole has not been oriented to support any particular group of consumers. One part of the company produces power, one part buys power, one part distributes power, one part dispatches power, and another restores power.

The agendas of these groups are very different. The group that dispatches power is interested in reliability. They have specific cooperative agreements with other utilities for providing a reliability reserve with a dispatch time of ten minutes or less. They are not truly concerned with cost and customer satisfaction. Although, they would not be adverse to being enabled to be concerned with either. They are concerned with having enough power available for the demand of that hour.

If it isn't bulk power it's not power

The bulk power group is concerned with producing/purchasing power at the lowest possible rate at any given time. Power is power. To illustrate this, when asking a Colorado utility to price the value of peaking power produced at a customer site, the answer was $0.25 kW-Month. Now the same customer had an interruptible rate and was being rebated $5.00 kW-month to have their power removed from the grid. Although the effect on the grid as far as total electrical demand would be identical, the utility has strict rules about producing versus removing power. What is missing from this equation is what would the customer be happier with. The newspaper company mentioned earlier is not interested in paying people to wait for a signal from the utility to leap into action. They do this because they have not been provided with alternative solutions.

So you want to connect to my grid?

The United States has the highest quality and reliability of power in the world. As the guardians of this track record and reputation stand the relaying and protection engineers. This very technical group of well trained individuals, rightfully so, pride themselves on controlling connections to the grid. This has proven to be a very useful function. This group of engineers is not biased by economic decisions. The public utilities commission stands by to ensure that they are not. However, their pace of work can be drastically effected by whether the utility that signs their paycheck has interest in approving the connection.

To make matters more intractable for someone who wants to install distributed generation, every utility has different requirements to parallel. This has prevented companies from being able to provide mass produced distributed generation systems in a cost effective manner, or for successful distributed generation systems from crossing utility service areas.

Build it and they will pay

Finally, the operating paradigm of the utility has been quite simple. Given the fact that they have earned fixed returns on their investments, it has proven to be more profitable to invest in infrastructure. The more infrastructure a utility could justify and get approved the higher their profit the next year. This paradigm is at an end. The site detailed in this paper is not characteristic of all sites in the Albuquerque area. It is the proverbial low hanging fruit, but "cherry picking" is good business.

References

Figures compiled by the Bureau of Business and Economic Research at the University of New Mexico

Figures taken directly off of Public Service of New Mexico's internet web page

Case number 2681 before the New Mexico Public Utility Commission

This hospital has peak loads of over 2.0 MW, making a zero power transfer limitation improbable

A 30% contingency margin was chosen to be more conservative than the typical 25% margin used in the industry

Based on figures from "Introduction to Integrated Resource T&D Planning, ABB Power T&D Company Inc. 1994

Figures based on Original Rider 11 to rates 4B, 5B, 11B, and 4000B from Public Service Company of New Mexico Electric Services

Figures based on Original Rider 11 to rates 4B, 5B, 11B, and 4000B from Public Service Company of New Mexico Electric Services

Based on estimates for premium services offered by various Caterpillar dealers for maintenance of standby generator sets

500 kW was chosen as 110% the capacity of the smallest generator, and assuming that the customer's peak and the failure of two generators would not occur simultaneously

1000 kW was chosen as 110% the capacity of the two smallest generator, assuming that the customers peak and the failure of the largest generator would not occur simultaneously

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top

HECO/Maui-DT-IR-2 <u>Ref: COM-T-2, Page 52, Line 1</u>

a. Has the County of Maui conducted any assessment of how many emergency generators are in operation on Maui?

RESPONSE: No, HECO was contracted by the State of Hawaii to conduct such an assessment and the assessment is identified in HECO's response to CA-SOP-IR-12.

b. If such an assessment has been conducted, please provide information on the number of emergency generators on Maui, including the make, model, size and age of the emergency generators.

RESPONSE: N/A

c. If the County of Maui has not made an overall assessment of the emergency generators on Maui, has it conducted an assessment of the emergency generators owned by the County of Maui? If so, please provide information on the number of emergency generators, including the make, model, size, age and location (i.e., street address of the units) of the emergency generators. If not, why has the County of Maui not made such an assessment?

RESPONSE: See response to item a. above.

HECO/Maui-DT-IR-3 Ref: COM-T-2, Page 57, Lines 1-9

a. Is the County of Maui proposing a $10,000 per new residence generation impact fee?

RESPONSE: No.

b. Please identify any other jurisdictions that currently charge a generation impact fee, and provide program details as to how customers "earn back" much or all of this generation impact fee.

RESPONSE: I have not surveyed utilities recently on this issue.

HECO/Maui-DT-IR-4 Ref: COM-T-2, Page 13, Lines 10-11

Please provide information on the land requirements (in acres per megawatt) for renewable DG systems?

RESPONSE: The requested information varies for various renewable DG systems, from zero land requirements for rooftop solar systems to minimal land requirements for the footprint of wind systems. See http://www.hawaii.gov/dbedt/ert/hes3/curves.html#photovoltaics for detailed data.

HECO/Maui-DT-IR-5 <u>Ref: COM-T-2, Page 29, Line 14</u>

a. What is an on-site system?

RESPONSE: An on-site system is one located at the premises of the customer, for which no transmission or other wheeling of energy is required.

b. Please describe geothermal heat pumps design and application?

RESPONSE: A geothermal heat pump is typically an electrically driven heat pump for which the exchange of energy takes place underground, as contrasted with an air-source heat pump which are above-ground. They are used for space and water heating and cooling worldwide. Detailed information is available at http://www.geoexchange.org/.

c. Can you provide examples of geothermal heat pump systems currently being used in the United States?

RESPONSE: There are utility incentives for geothermal heat pumps in many states, including Washington, Oregon, Idaho, Montana, California, and Oklahoma. See http://www.geoexchange.org/ for additional information.

d. Can you provide examples of geothermal heat pump systems currently being used in Hawaii?

RESPONSE: No.

HECO/Maui-DT-IR-6 Ref: COM-T-2, Page 43, Line 22

a. What is an off-site renewable energy wind system?

RESPONSE: An off-site renewable energy wind system is one located on property not adjacent to the location where the energy is consumed.

b. Please provide examples of off-site wind systems in Hawaii.

RESPONSE: All of the existing wind farms in Hawaii generate for off-site consumption. This includes wind farms on the island of Hawaii.

HECO/Maui-DT-IR-7 Ref: COM-T-2, Page 46, Lines 16-18
Please provide examples of off-site biomass systems in Hawaii.

RESPONSE: H-Power generated steam and electricity from biomass on Oahu, macadamia nut biomass energy on the Big Island, and bagasse biomass energy on Maui and Kauai. See http://www.hawaii.gov/dbedt/ert/bioma_hi.html for additional information.

HECO/Maui-DT-IR-8 <u>Ref: COM-T-2, Page 47, Lines 12-15</u>

a. Please provide information on how these wind energy systems are reducing the peak load for the utility?

RESPONSE: Whenever the units operate during on-peak periods, they provide peak load relief to the utilities.

b. Please provide information on how these wind energy systems are providing capacity to the utility when the wind is not blowing?

RESPONSE: They do not. The measure of system reliability, and therefore the capacity credit, is a probabilistic measurement, typically done through loss of load probability (LOLP) studies. These show that adding generation at ANY hour results in improved system reliability. The capacity credit can be measured as the ratio of conventional generating capacity to wind capacity needed to produce an equivalent improvement in LOLP. For example, if 10 megawatts of wind capacity provide the same improvement in supply reliability as 2 megawatts of conventional capacity, the wind capacity credit would be 20%. Therefore, even a system that provides zero benefit during the "peak period" may deserve a capacity credit.

HECO/Maui-DT-IR-9 Ref: COM-T-2, Page 48, Lines 14-16

a. Please provide examples of on-site photovoltaic systems in Hawaii.

RESPONSE: See http://www.hawaii.gov/dbedt/ert/pv_hi.html for examples. The house I stay at on the Big Island is solar PV electric; the community of Milolii is heavily solar-electric.

b. Please provide examples of on-site solar thermal electric generation systems in Hawaii.

RESPONSE: Mr. Lazar is not aware of any solar thermal electric generating systems in Hawaii. A study of these is available at: http://www.hawaii.gov/dbedt/ert/segs92.html.

c. Please provide examples of on-site use of biomass and waste materials in Hawaii.

RESPONSE: The cane-waste electric generation process at Puunene and formerly at many other locations in Hawaii are examples of this. H-Power is a waste-energy producer.

d. Are all these on-site renewable systems feasible and viable in Hawaii?

RESPONSE: Yes. The cost-effectiveness is a site-specific issue, often affected by line extension costs and/or connection charges.

HECO/Maui-DT-IR-10 <u>Ref: COM-T-2, Page 49, Lines 1-2</u>

a. Please provide information on how the on-site photovoltaic systems in Hawaii are reducing peak demand in Hawaii.

RESPONSE: The testimony does not state that this is the case. To the extent that homes with on-site solar systems are not connected to the grid but would be grid-connected absent solar electric systems, we can assume the utility peak demand is reduced by the diversified demand that those homes would otherwise impose.

b. Please provide information on how the on-site solar thermal electric generation system are reducing peak demand in Hawaii.

RESPONSE: The testimony does not state that this is the case.

HECO/Maui-DT-IR-11 <u>Ref: COM-T-1, Page 12, Lines 7-8</u>
The testimony states "Appropriately priced standby rates are important for creating a level playing field between DG and conventional electric utility services."

a. Please provide all calculations and workpapers that show how "appropriately priced standby rates" would be determined.

RESPONSE: Workpapers have not been prepared. The analysis required would be to determine the level of additional generating capacity needed to preserve the same system LOLP with the addition of DG systems. For example, if the presence of 100 mw of DG systems required that the utility acquire 15 MW of standby capacity to preserve the system LOLP at an unchanged level, the appropriate standby generation charge would be 15% of the fixed cost of generating capacity, plus appropriate variable costs when the systems are actually providing standby service.

This type of study was prepared in Docket 7310, and the results provided to HECO at that time. If a replacement copy of the study is required, please contact Mr. Lazar directly.

b. Please provide all calculations and workpapers that show how such "appropriately priced standby rates" would create a level playing field between DG and conventional electric utility services.

RESPONSE: Under such an approach, DG systems would pay only for the capacity required to ensure that other customers are not adversely affected by their use of system standby resources. The example above shows the type of analysis required.

HECO/Maui-DT-IR-12 Ref: COM-T-1, Page 16, Lines 10-12
The testimony states "the COM recommends that the Commission direct MECO to modify its planned Capacity Buy-back ("CBB") program into an expanded virtual power plant program."

a. What would be the capital and operating and maintenance costs of the "virtual power plant program"?

RESPONSE: This would be ascertained by MECO during the development of the program.

b. What would be the benefits of the "virtual power plant program"?

RESPONSE: The planned benefits would include improving the reliability of standby generators, improving the reliability of the grid, and facilitating the deployment of standby generator.

c. Would such a "virtual power plant program" be cost-effective? If so, please provide workpapers that show that such a program would be cost-effective.

RESPONSE: We expect that MECO could design a program that is cost effective.

HECO/Maui-DT-IR-13 Ref: COM-T-2, Page 52, Lines 14-15

The testimony states "HELCO contracted with several large customers with emergency generators to switch some of their loads to their own generators during high-load hours."

a. What is the basis for this statement? Please provide copies of any materials relied on in support of the statement.

RESPONSE: Oral discussions with HELCO staff at the time, and with Mr. Chuck Totto, then Director of the Division of Consumer Advocacy.

b. Please identify the large customers with emergency generators with whom HELCO allegedly had contracts to switch some of their loads to their own generators during high-load hours.

RESPONSE: A list was not obtained. It included the county water and sewer systems, and several of the large hotels.

c. Please provide a copy of any one of such contracts.

RESPONSE: We do not possess any copies of the contracts.

HECO/Maui-DT-IR-14 Ref: COM-T-2, Page 9, Lines 2-5
Please illustrate the concept of "front-loaded" cost recovery.

RESPONSE: An illustration of this follows. Assume a measure costing $100,000 with a 5-year life, and a 10% rate of return. The table below demonstrates the capital recovery for such a measure, based on an average rate base approach to cost recovery:

Year	Rate Base	Return	Depreciation	Total Capital Cost to Ratepayers
1	$90,000	$9,000	$20,000	$29,000
2	$70,000	$7,000	$20,000	$27,000
3	$50,000	$5,000	$20,000	$25,000
4	$30,000	$3,000	$20,000	$23,000
5	$10,000	$1,000	$20,000	$21,000

HECO/Maui-DT-IR-15 Ref: COM-T-2, Page 44, Lines 19-22
Please provide all workpapers and analysis supporting the "30%-45%" utility fuel efficiency cited in the referenced statement.

RESPONSE: See FERC Form 1, Pages 402-403 for heat rates on utility generating plants. These are available at www.ferc.gov for parties not having copies.

HECO/Maui-DT-IR-16 Ref: COM-T-1, Page 15, Lines 10-11
The County of Maui states "The COM recommends the adoption of reasonable interconnection standards and procedures of DG systems by the Companies."

a. Please fully explain what the County of Maui mean when it states "reasonable interconnection standards and procedures".

RESPONSE: Interconnection standards that are generally accepted within the industry, such as IEEE, and recognize that small DG systems cannot afford high interconnection costs.

b. Are the interconnection standards and procedures included in MECO's Rule 14.H "reasonable interconnection standards and procedures"? If the answer is anything other than an unqualified "yes", please fully explain why the County of Maui alleges that the interconnection standards and procedures in MECO's Rule 14.H are not reasonable, including in the explanation the specific terms, conditions, provisions and/or other passages that the County of Maui alleges are not reasonable, and how the County of Maui proposes to modify the interconnection standards and procedures in MECO's Rule 14.H to make them reasonable.

RESPONSE: We have not alleged that Rule 14.H is unreasonable. Our point was that Rule 14.H may not address all sizes of DG systems.

HECO/Maui-DT-IR-17 Ref: COM-T-2, Page 48, Lines 1-2
Please provide a list of utilities that "recognize the capacity value of wind generation" in the development of their standby rates.

RESPONSE: Mr. Lazar is not aware of any that do this specifically. There are several that recognize the capacity value of wind in the purchase rates they expect to pay for wind generation. These include the California IOUs and Pacific Power and Light Company.

HECO/Maui-DT-IR-18 Ref: COM-T-2, Page 46, Lines 8-10
Please clarify the emergency generator "option" that the witness does not consider important in this proceeding.

RESPONSE: The question seems to misunderstand the testimony. The "option" in this passage is stand-alone, conventional fossil fuel generation without use of waste heat, which has similar fuel efficiency to utility generation. The witness does not consider that option to be important to encourage through o taken in this proceeding, since it does not reduce fossil fuel dependency. Emergency generator use has similar fuel efficiency, but is not the "option" referred to.

HECO/Maui-DT-IR-19 <u>Ref: COM-T-2, Page 49, Lines 9-11</u>

a. Please provide a list of utilities with hookup fees which encouraged builders to install solar water heaters.

RESPONSE: The testimony does not indicate that the witness is aware of any. However, many utilities have distribution connection charges measured on an amp, panel size, or transformer kw basis. All of these would provide an incentive for a customer to choose a solar water heater with storage, or a solar water heater with a load controller.

Two good examples are PLN in Indonesia, and Eskom in South Africa. Both have rate designs that are sharply higher in cost for customers with larger connected loads, providing an incentive for customers to install only essential services, and to choose the more efficient appliances where these reduce the connected loads.

b. Would the County of Maui agree that changes to the Model Energy Code requiring the use of solar water heaters would be just as effective in increasing the penetration of solar water heaters as a hookup fee? If the answer to part a. above is no, please explain.

RESPONSE: The County of Maui has not made such an assessment.

HECO/Maui-DT-IR-20 <u>Ref: COM-T-2, Page 50, Lines 13-21</u>

a. Please provide a list of utilities currently employing the "virtual power plant concept".

b. Please provide a copy of each utility's tariff outlining the terms and conditions, and rates associated with the operation of a "virtual power plant".

RESPONSE: See response to HECO/Maui-DT-IR-1.

HECO/Maui-DT-IR-21 <u>Ref: COM-T-2, Page 51, Lines 5-8</u>
Who would pay for the costs of the "synchronization equipment and safety devices, and the development of "coordinated telemetry and centralized dispatch system" that are required to develop the County of Maui's proposed "virtual power plant"?

RESPONSE: The testimony assumes that these costs would be borne primarily by the utility, and included in rate base and operating expense like other peaking generation costs. Other mechanism may be possible.

HECO/Maui-DT-IR-22 Ref: COM-T-2, Page 56, Lines 1-4
Please provide evidence that MECO's line extension policy encourages "sprawl".

RESPONSE: The testimony does not make this statement.

HECO/Maui-DT-IR-23 Ref: COM-T-2, Page 56, Lines 10-13

a. Please provide all workpapers and analysis to support the claim that "new customers add more to costs than to revenues for the utility".

RESPONSE: See pages 39 - 43 of the testimony, and COM-201.

b. Is it the County of Maui's position that the impact of a "new customer's load" on utility system is different from the impact of an existing customer's load growth? Please explain your position.

RESPONSE: The impact on the utility system would not be different, except with respect to local distribution issues.

c. Will the County of Maui's proposed generation impact fee or connection charge apply to all new residential and non-residential customers?

RESPONSE: The concept presented by Mr. Lazar would apply to all customers.

d. Please provide a list of utilities that have implemented generation impact fees or connection charges that is the same or similar to the County of Maui's proposal.

RESPONSE: No examples were identified in the testimony.

e. How would the County of Maui's proposed generation impact fee affect the deployment of distributed generation to the utilities' existing customers?

RESPONSE: For customers with expanding loads, the impact would be identical to that for new customers.

f. Is it the County of Maui's intent to only effect or encourage the installation of distributed generation by the utilities' "new customers"?

RESPONSE: No.

HECO/Maui-DT-IR-24 Ref: COM T-2, Page 58, Line 15-18

Please provide the workpapers showing the calculation of the Residential Consumer Owner financing of $384 and $335, and the Utility Financing of $718 in the referenced table.

RESPONSE: See the following table.

Cost of Solar Water Heater Consumer vs. Utility Ownership				
		Customer-Owned		Utility - Owned
Capital Cost		$3,500		$3,500
Debt Portion		100.00%		55.00%
Debt Rate		7.00%		8.00%
Equity Portion		0.00%		45.00%
Equity Rate		0.00%		12.00%
Lifetime		15		15
Depreciation Expense		$0.00		$233.33
Return on Debt				$154.00
Tax Benefit of Return on Debt	35.00%			-$53.90
Return on Equity				$189.00
Tax Cost of Return on Equity	35.00%			$101.77
Total Carrying Cost				$624.20
Grossup rate for State and Local Utility Taxes				1.15
Mortgage Amount		$3,500.00		
Annual Mortgage Payment		**$384.28**		
Interest Portion		$245.00		
Personal Income Tax Rate	20.00%			
Tax Benefit of Interest		$49.00		
Net Cost to Consumer		**$335.28**		**$717.83**

HECO/Maui-DT-IR-25 Ref: COM-T-2, Page 60, Lines 14-16
Please provide a list of electric utilities that have implemented "full cost" generation impact fees.

RESPONSE: See response to HECO/Maui-DT-IR-3.

HECO/Maui-DT-IR-26 Ref: COM-T-2, Page 61, Lines 1-4
Please provide a list of electric utilities that have implemented generation impact fees based on the "second approach" discussed in the referenced statements.

RESPONSE: See response to HECO/Maui-DT-IR-3. Several utilities implemented DSM programs based on a marginal-minus-average (also known as the no-loser's test) approach. Examples include Puget Sound Energy, Washington Water Power, Pacific Power and Light Company. All have now been supplanted by programs using the Total Resource Cost test.

HECO/Maui-DT-IR-27 <u>Ref: COM-T-2, Page 66, Lines 13-16</u>
Please provide all workpapers and analysis supporting the claim of the "current subsidies of new customers by existing customers."

RESPONSE: See exhibit COM-201.

HECO/Maui-DT-IR-28 Ref: COM-T-2, Page 67, Lines 20-21
Does the County of Maui know of any utilities where impact fees have resulted in the deferral of the construction of generating facilities? If yes, please provide the names of the utilities, the contact person(s) names and telephone numbers, and any evidential reports or documents from such utilities.

RESPONSE: No.

HECO/Maui-DT-IR-29 Ref: COM-T-2, Page 70, Lines 15-17
Please provide all analysis and workpapers supporting the claim that providing service under MECO's Schedule P for standby service "results in customers making excessive contribution to MECO's fixed costs".

RESPONSE: Schedule P is designed to recover the full costs of generating capacity used by full-requirements customers. It does not include a probability-weighted adjustment for partial-requirements customers reflecting their diversity. The requested calculation is complex and has not been performed, due to the following important elements:

1) Difference between embedded and marginal cost,
2) Probability-weighted capacity requirements for standby service,
3) Load factor blocking in Schedule P, and,
4) Rolled-in nature of Schedule P, including both baseload and peaking resources.

HECO/Maui-DT-IR-30 Ref: COM-T-2, Page 85, Lines 11-13

Please explain how the proposed inverted rate design for the residential class will facilitate the development and deployment of distributed generation.

RESPONSE: The inverted rate will stimulate solar photovoltaic system construction, if the upper block is high enough to make such systems cost-effective. It might also facilitate the development of distributed energy resources, such as solar water heat.

HECO/Maui-DT-IR-31 <u>Ref: COM T-2, Page 91, Line 20-21</u>
Please provide copies of long-term contracts where customer demands are a significant percentage of total utility sales.

RESPONSE: Mr. Lazar has copies of contracts between Puget Sound Energy and several retail customers, and between Burbank Water and Power and two retail customers. All of these contracts are protected by confidentiality agreements and/or attorney-client privilege in other jurisdictions. If permission is obtained to release these, they will be made available for inspection and copying at the office of the County of Maui.

HECO/Maui-DT-IR-32 Ref: COM-T-2, Pages 92-93

a. Please provide a list of electric utilities that provide preferential treatment to the County or municipal agencies as to provide wheeling service only to these customers.

RESPONSE: We do not possess such a list.

b. Please explain what is meant by the County being "permanent components of the community".

RESPONSE: The County will be a member of the community essentially forever. Businesses come and go, residents move in and out. Businesses suffer bankruptcy. People die. The County, as an institution, is not going away.

c. Please provide a list of projects that the County of Maui has developed that resulted in "economic savings" and where such savings were "returned to the public", or where the "economic savings is returned to the same people."

RESPONSE: All construction projects that received DSM rebates from MECO resulted in savings to the public. The County of Maui does not have a list of said projects, but expects MECO to have such a list.

HECO/Maui-DT-IR-33 <u>Ref: COM-T-2, Page 94, Lines 5-7</u>
Please explain how Performance-Based Ratemaking will facilitate the development and deployment of distributed generation.

RESPONSE: The testimony indicates that development and deployment of distributed generation will shift investment from the utility's rate base to individual customers making investment to serve their needs. This will tend to cause a slowing of growth in the utility rate base. Conventional rate-of-return regulation provides profit as a function of investment, so the effect of this would be to slow profit growth. We view this as a deterrent to utility support of DG. Moving to an alternative form of regulation can overcome this negative effect.

HECO/Maui-DT-IR-34 Ref: COM-T-2, Page 50, Lines 15-21
Has the County of Maui had any discussions with hospitals and other owners of emergency generators to determine the level of their interest in turning over the ownership and operation of their emergency generators to be used as a utility resource serving all customers instead of serving the emergency generators' intended specific load at the customer's location?

RESPONSE: The proposed virtual power plant does not require electric utility ownership of the standby generators. Also, the standby generators would continue to serve the customer, as well as the electric utility, as would also be the case in MECO's proposed capacity buy-back program.

HECO/Maui-DT-IR-35 Ref: COM-T-2, Page 19, Lines 26-27
What would the County of Maui term an enterprise that offers all of its customers competitive rates via a tariff, regardless of the customers' alternatives?

RESPONSE: Not enough information in the question to response. If the "competitive rates" were cost-based and non-discriminatory, the term "public utility" might be applicable. However, if the "competitive rates were not cost-based, or discriminated between customers depending on their available alternatives, the term "discriminating monopolist" comes to mind.

HECO/Maui-DT-IR-36 <u>Ref: COM-T-2, Page 24, Lines 9-11</u>

a. Please explain the basis for the County of Maui's position that assisting customers with the selection of CHP equipment is little different than providing information on efficient household appliances.

RESPONSE: Customers need quality information in order to make rational decisions on complex technical issues such as energy efficiency or distributed generation. Issues such as economic savings, reliability, availability of local service and support, quality assurance and quality control are all elements of both energy efficiency options and DG options. The utility currently does this for energy efficiency measures, but not for DG. Customers need both.

b. What is the County of Maui's understanding of and experience in specifying equipment for a CHP installation at a customer site?

RESPONSE: The County of Maui does not specify CHP equipment for electric utility customers.

HECO/Maui-DT-IR-37 <u>Ref: COM-T-1, Page 9, Lines 4-9</u>

a. What is the County of Maui's definition of "privately used consumer energy products and services?"

RESPONSE: This refers to products and services for particular individuals. For more elaboration on this matter, see our response to HECO/Maui-DT-IR-41, item c.

b. From the standpoint of HRS 269, what differentiates a utility-owned and operated CHP system at a customer site from a utility-owned and operated transformer that is installed at a customer site and is dedicated for the customer's use? (Note that a transformer may also be customer-owned.)

RESPONSE: The difference is that a transformer, much like a utility meter, is ancillary equipment in support of public utility services, whereas customer-sited CHP systems, serving particular individuals, are not ancillary equipment in support of public utility services. For further explanation, see our response to HECO/Maui-DT-IR-41, item c.

HECO/Maui-DT-IR-38 Ref: COM-T-1, Page 7, Lines 20-23 through Page 8, Lines 1-14

By Decision and Order No. 17957, filed August 8, 2000, Docket No. 99-0369, the Commission approved the installation of DG units at MECO's Hana Substation. Is it the County of Maui's position that the Hana Substation DG units are "prohibited" and that the Commission made an error in approving the installation of these DG units.?

RESPONSE: No. They are utility-owned units that support tariff utility service delivered over the grid.

HECO/Maui-DT-IR-39

The County of Maui's May 7, 2004 Preliminary Statement of Position discussed the fourteen issues set forth in Prehearing Order No. 20922, filed April 23, 2004. Please state whether the County of Maui's position on the fourteen issues has changed from the position set forth in its Preliminary Statement of Position. If the answer is anything other than an unqualified "no", please (1) identify each issue on which there has been a change in position, (2) state and fully discuss each changed position on the issues, and (3) provide the basis for each changed position on the issues (including a copy of any material relied in support of each changed position).

RESPONSE: No changes in position have been made. The testimonies T-1 and T-2 submitted on July 14, 2004 supercedes the Preliminary Statement of Position submitted on May 7, 2004.

HECO/Maui-DT-IR-40 <u>Ref: COM-T-1, Page 8, Lines 3-14</u>
The County of Maui states that MECO was granted franchises "to own and operate power grid systems (centrally generated electricity delivered over power lines) because power grid systems were generally considered natural monopoly enterprises." Please provide the basis for this statement and include a copy of any materials relied on in support of such statement.

RESPONSE: The basis for this statement is from the publication, "The Electric Utility Franchise Expiration and Renewal Process," which states on page 19:

> "Today, policy restrictions or prohibitions against competition are justified on grounds that electric utilities are "natural monopolies" and that competition would lead to wasteful duplication of facilities.
>
> States prohibit or legislate against competition by allowing exclusive franchises and/or service areas, and through the state certification process for new constructions. The following statement by an early Chairman of the Connecticut Public Utilities Commission typifies prevailing thought:
>
>> *"Public Service or utility companies are organized and granted certain franchise rights and privileges as public agents to supply the public within their respective franchise territories with a specified public necessity...the supplying of what is defined as a public utility is in its nature*

monopolistic, and for this reason exclusive grants or franchises are issued, and operation thereunder is subject to public regulation."

The referenced document will be made available for inspection upon request.

HECO/Maui-DT-IR-41 <u>Ref: COM-T-1, Page 8, Lines 16-18</u>
The County of Maui states "[t]he ownership and operation of consumer DG and DER for private use does not appear to be public utility activity, as defined by Hawaii Revised Statutes ("HRS") Chapter 269-1."

a. Please fully explain what the County of Maui means when it states "consumer DG and DER".

RESPONSE: This refers to DG and DER systems that are used primarily by a particular individual and is sited on the individual's property.

b. Please fully explain what the County of Maui means when it states "for private use".

RESPONSE: This refers to DG and DER systems that are used primarily by a particular individual.

c. Please fully explain what the County of Maui means when it states "public utility activity". Please provide the basis for such explanation and provide any materials relied on by the County of Maui in support of such statement.

RESPONSE: This refers to activities of "public utilities." The basis for what constitutes a "public utility" is the Hawaii Supreme Court Opinion in HELCO's appeal of the Commission's findings and conclusions in Docket No. 4779, in the matter of the application of Wind Power Pacific Investors-III and Waikoloa Water Co., Inc. Said Opinion identified "public utility" as follow:

> "[W]hether the operator of a given business or enterprise is a public utility depends on whether or not the service

rendered by it is of a public character and of public consequence and concern, which is a question necessarily dependent on the facts of the particular case, and the owner or person in control of property becomes a public utility only when and to the extent that his business and property are devoted to a public use. The test is, therefore, whether or not such person holds himself out, expressly or impliedly, as engaged in the business of supplying his product or service to the public, as a class, or to any limited portion of it, as contradistinguished from holding himself out as serving or ready to serve only particular individuals."

See the attached Supreme Court ruling (three pages).

In the Matter of the Application of WIND POWER PACIFIC INVESTORS-III and WAIKOLOA WATER CO., INC. for Certification of Qualifying Small Power Production Facility Pursuant to Subchapter 2, Rule 6-74-9 Established by the Department of Budget & Finance, State of Hawaii, Entitled "Standards for Small Power Production and Cogeneration in the State of Hawaii."

NO. 9418

APPEAL FROM PUBLIC UTILITIES COMMISSION

(DOCKET NO. 4779)

AUGUST 29, 1984

LUM, C.J., NAKAMURA, PADGETT, HAYASHI AND WAKATSUKI, JJ.

ADMINISTRATIVE LAW — *scope of review in general — harmless or prejudicial error.*

PUBLIC UTILITIES — *judicial review or intervention — appeal from orders of commission — review and determination in general.*

While the Public Utilities Commission may not have followed procedural requirements to the letter, where the irregularities complained of do not prejudice the substantial rights of the appellant, the court will not reverse the PUC's decision.

SAME — *regulation — service and facilities.*

The Public Utilities Commission did not err in determining that a facility and not the operator qualifies to receive the benefits of qualification as a small power production facility under HRS § 269-27.2 and Administrative Rules, Title 6, Chapter 74.

OPINION OF THE COURT BY WAKATSUKI, J.

Wind Power Pacific Investors-III (WPPI-III) and Waikoloa Water Co., Inc. (WWC) jointly applied to the Public Utilities Commission (PUC) for a certification as a qualifying small power production facility (qualifying facility or QF). WPPI-III and WWC proposed building a small power production facility utilizing wind energy at Waikoloa on the Island and County of Hawaii (Big Isle). The plan is to produce electrical energy to primarily operate WWC's water pumps and to sell any excess energy to Hawaii Electric Light Co. (Helco), an electric utility operating on the Big Isle. The PUC granted the certification and Helco appeals. We affirm.

I.

Helco complains that: (a) the PUC's finding that the application had been amended by the deletion of the two ten-kilowatt (kw) windmills was clearly erroneous, or based upon erroneous procedure, and the PUC's conclusion that the application met the single ownership requirement of a QF was also erroneous; (b) the PUC improperly considered a power sales agreement which was executed and entered into by WWC and WPPI-III subsequent to the evidentiary hearing.

In reviewing the record, we find that the deletion of the two ten-kw windmills and the proposed ownership/operational agreement were fully and amply discussed during the hearings before the PUC. Helco cannot now complain of surprise or the inability to rebut the facts considered by the PUC. We are not convinced that further hearings will produce new evidence for the PUC to consider.

While the PUC may not have followed procedural requirements to the letter, we hold that the irregularities complained of do not prejudice the substantial rights of Helco. HRS § 91-14(g); *Survivors of Medeiros v. Maui Land & Pineapple Co.*, 66 Haw. 290, 293, 660 P.2d 1316, 1319 (1983). We conclude that no error was committed.

II.

Helco argues that WPPI-III is the true operator of the qualifying facility and not WWC, and therefore, the granting of the certificate was in error.

Under Hawaii Revised Statutes (HRS) § 269-27.2, electric utilities are required to purchase any energy made available by a qualifying small power production facility at a price not less than 100 per cent of the cost avoided by the utility when the utility purchases the electrical energy rather than producing the electrical energy. Administrative Rules § 6-74-21. *See generally* Administrative Rules, Title 6, Chapter 74. The legislative purpose and intent of the mandatory purchase and price statute is to encourage the development of alternate energy sources to lessen the state's dependence on fossil fuels. HRS § 269-27.2; 1977 Haw. Sess. Laws, Act 102, § 1.

The PUC in interpreting its own rules, determined that the *facility* and not the operator qualifies to receive the benefits of qualification. Such interpretation must be given deference by this court unless contrary to public policy. *Camara v. Agsalud*, 67 Haw. 212, 685 P.2d 794 (1984). The interpretation given by the PUC of Rules 6-74-4, 6-74-5, and 6-74-7 *supports* the public policy of encouraging development of alternate energy sources established by the Legislature. Furthermore, the PUC followed the Federal Energy Regulatory Commission's lead in interpreting the rules in question.[3]

We agree with the PUC that the relationship between WPPI-III and WWC in establishing the facility has no effect on whether the facility qualifies as a QF.

III.

Helco contends that the PUC erred in concluding that WPPI-III is not a public utility.

HRS § 269-1 defines a public utility as

> every person who may own, control, operate, or manage as owner, lessee, trustee, receiver, or otherwise . . . any plant or equipment . . . directly or indirectly for public use . . . for the production, conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas or oil . . . ; provided that the term . . . (7) shall not include any person which (A) controls, operates, or manages plants or facilities for production, transmission, or furnishing of power primarily or entirely from non-fossil fuel sources, and (B) provides, sells, or transmits all of such power, except such power as is used in its own internal operations, directly to a public utility for transmission to the public . . . .

Helco argues that WPPI-III falls within the definition of a public utility under HRS § 269-1 because WPPI-III owns a power production plant for indirect public use. Helco further argues that WPPI-III does not fall within the exception of sub-paragraph (7) of HRS § 269-1 because WPPI-III will not sell all of the electrical power directly to Helco, but rather, WPPI-III will sell the power to WWC and through WWC, to Helco.

The term "public utility" implies a public use. The regulation of public utilities ensures continuation of service to the public with reasonable efficiency, at fair rates, and without discrimination against particular users or classes of users. A.J.G. Priest, *I Principles of Public Utility Regulation*, Ch. 1, generally; 73B C.J.S. *Public Utilities* § 2.

> [W]hether the operator of a given business or enterprise is a public utility depends on whether or not the service rendered by it is of a public character and of public consequence and concern, which is a question necessarily dependent on the facts of the particular case, and the owner or person in control of property becomes a public utility only when and to the extent that his business and property are devoted to a public use. The test is, therefore, whether or not such person holds himself out, expressly or impliedly, as engaged in the business of supplying his product or service to the public, as a class, or to any limited portion of it, as contradistinguished from holding himself out as serving or ready to serve only particular individuals.

73B C.J.S. *Public Utilities* § 3. *See also* Priest, *supra*, p. 10-13; *Wilhite v. Public Service Commission*, 150 W.Va. 747, 149 S.E.2d 273 (1966).

The PUC found that WPPI-III's property was not dedicated to public use even though WPPI-III sold all of the electric energy produced by WPPI-III to WWC, which in turn sells the excess energy to Helco. Upon review of the record, we cannot conclude

[3] The federal rules, 18 C.F.R. § 292.201 to § 292.207, implementing section 201 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, are substantially identical to Administrative Rules, Title 6, Chapter 74, Subchapter 2. In an analysis of 18 C.F.R. § 292.203 (corresponding to Administrative Rule § 6-74-4), the Federal Energy Regulatory Commission stated:

> There was some confusion in the comments as to who actually qualifies under this program. *The facility qualifies* and that entitles the owners and operators of the facility to receive the benefits of qualification under this part. (Emphasis added.)

45 Fed. Reg. 17963 (1980)

that the PUC's finding was clearly erroneous. Further, the legislature enacted sub-paragraph (7) of HRS § 269-1 specifically to encourage the commercial development of renewable energy resources by producers who desired not to be deemed public utilities. Act 77, § 1, 1980 Haw. Sess. Laws. We conclude that WPPI-III is not a public utility under HRS § 269-1.

IV.

We hold that the conclusions reached by the PUC are not contrary to the policies supporting the regulation of public utilities, and the intent and policy of our legislature to reduce our dependence on fossil fuels. We further hold that Helco's other contentions are without merit.

Affirmed.

Barry M. Utsumi for Appellant Hawaii Electric Light Company, Inc.

Gerald A. Sumida (Alan T. Kido with him on the brief) for Appellee Wind Power Pacific Investors-III and Waikoloa Water Co., Inc.

In the Matter of the Claim of: RUPERTO MALDONADC Petitioner-Appellant, and TRANSPORT INDEMNITY Respondent-Appellee

NO. 9323

(CIVIL NO. 71476)

CERTIORARI TO THE INTERMEDIATE COURT OF APPEALS

SEPTEMBER 5, 1984

LUM, C.J., NAKAMURA, PADGETT, HAYASHI, JJ., AND CIRCUIT JUDGE MOON, IN PLACE OF ASSOCIATE JUSTICE WAKATSUKI, DISQUALIFIED

NO-FAULT INSURANCE — *net wage loss — effect of workers' compensation payment·*
Where an employee is injured in an automobile accident while in the cour and scope of his employment and his resulting wage loss is partially paid by h benefits under the workers' compensation law, the amount not so paid a actually lost by the employee is his monthly earnings loss for purposes of HR Chapter 294, the no-fault insurance statute.

OPINION OF THE COURT BY PADGETT, J.

We granted certiorari in this appeal by a wage earner injure in an automobile accident. The Intermediate Court of Appea affirmed a circuit court judgment upholding the refusal, by tl no-fault insurance carrier involved, to pay him his actual wage lo of $602.34 per month resulting from the accident. We reverse.

Petitioner Ruperto Maldonado, a bus driver earning $1,534 month, was injured in an accident while driving an MTL bus North King Street in Honolulu. Because of his injuries, he w disabled, and could not continue to work. The workers' compens tion benefits payable to him were $931.66 a month. Thus, he exp rienced an actual monthly wage loss of $602.34.

He made a claim for that amount to Transport Indemnity, t no-fault insurer of the bus. It denied his claim. Petitioner th requested a review by the Insurance Division of the Department Commerce & Consumer Affairs (formerly the Department Regulatory Agencies). The assigned hearings officer ruled in pe

HECO/Maui-DT-IR-42 <u>Ref: COM-T-1, Page 10, Lines 7-15</u>
The County of Maui states "an alleged case of market power was documented by the National Renewable Energy Laboratory ('NREL') in their study, 'Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects.' [Footnote 6 omitted.] The case study was not reported by Pacific Machinery, Johnson Controls, or Noresco. This case study is anonymously identified in the publication as Case #14–120-kW Propane Gas Reciprocating Engine for Base Load Service at Hospital. The actual facility was not a hospital, but the identity of the facility was changed to help protect the identity of the implicated electric utility company."

a. Please provide the basis for the statement that "the actual facility was not a hospital". Please provide a copy of any material relied on in support of this statement.

b. Please provide the basis for the statement that "the identity of the facility was changed to help protect the identity of the implicated electric utility company." Please provide (1) a copy of any material relied on in support of this statement, (2) the identity and location of the actual facility, and (3) the identity of the vendor (e.g., Pacific Machinery, Johnson Controls, Noresco, etc.) working with the "hospital" to have the DG unit installed.

RESPONSE: Mr. Kobayashi moderated the "Retail Energy Services Industry Forum" ("Forum") on Maui on August 31, 1999. Attendance included energy service companies from around the state and the feature speaker was Ms. Sarah McKinley, Executive Director of the Distributed Power Coalition of America. During the Forum, the CHP system installed at the Pohai Nani Good Samaritan adult assisted living center on Oahu was discussed. Ms. McKinley indicated that she would try to arrange for the Pohai Nani Good Samaritan case study to be included in the NREL study being drafted at that time and Mr. Kobayashi verified that this arrangement took place. The Pohai Nani Good Samaritan CHP system was developed by Hess

Microgen. The pertinent contents of the NREL study is attached. Note that while Case #14 does not identify the state in the text, Table 2-4 and Figures 2-4 and 2-6 do identify Hawaii as the state associated with the 120 kW propane gas reciprocating engine system.

See attachment (six pages).

Table 2-4
Barrier Related Interconnection Costs- Costs Above Normal ($)

Case	Technology	Costs Above Normal
2.4-kW PV System in NH	PV	$ 200
17.5-kW Wind Turbine in IL	W	$ 300
300-W PV System in PA	PV	$ 400
0.9-kW PV System in New England	PV	$ 1,200
3.3-kW Wind/PV System in AZ	PV/W	$ 4,000
140-kW NG IC System in CO	NG	$ 5,000
10-kW Wind Turbine in TX	W	$ 6,000
20-kW Wind/PV System in Midwest	PV/W	$ 6,500
120-kW Propane Gas Reciprocating Engine in HI	Propane	$ 7,000
37-kW Gas Turbine in CA	NG	$ 9,000
90-kW Wind Turbine in IA	W	$ 15,000
132-kW PV System in CA	PV	$ 25,000
43-kW PV System in PA	PV	$ 35,000
2100-kW Wind Turbines in CA	W	$ 40,000
40 sites of 60-kW NG IC Systems in CA	NG	$ 50,000
50-kW Cogeneration System in New England	CG	$ 50,000
75-kW NG Microturbine in CA	NG	$ 50,000
260-kW NG Microturbines in LA	NG	$ 65,000
703-kW Steam turbine in MD	CG	$ 88,000
Seven sites of 650-kW IC NG System in NH	NG	$ 300,000
500-kW Cogeneration System in New England	CG	$ 500,000
21-MW NG Cogeneration System in TX	CG	$ 1,000,000
15-MW Cogeneration System in MO	CG	$ 1,940,000
26-MW Gas Turbine in LA	NG	$ 2,000,000
3 to 4-MW NG IC System in KS	NG	$ 7,000,000

Figure 2-4
Barrier Related Interconnection Costs Above Normal ($/kW)

Costs are estimated by Owners/Project Developers as the costs above normally

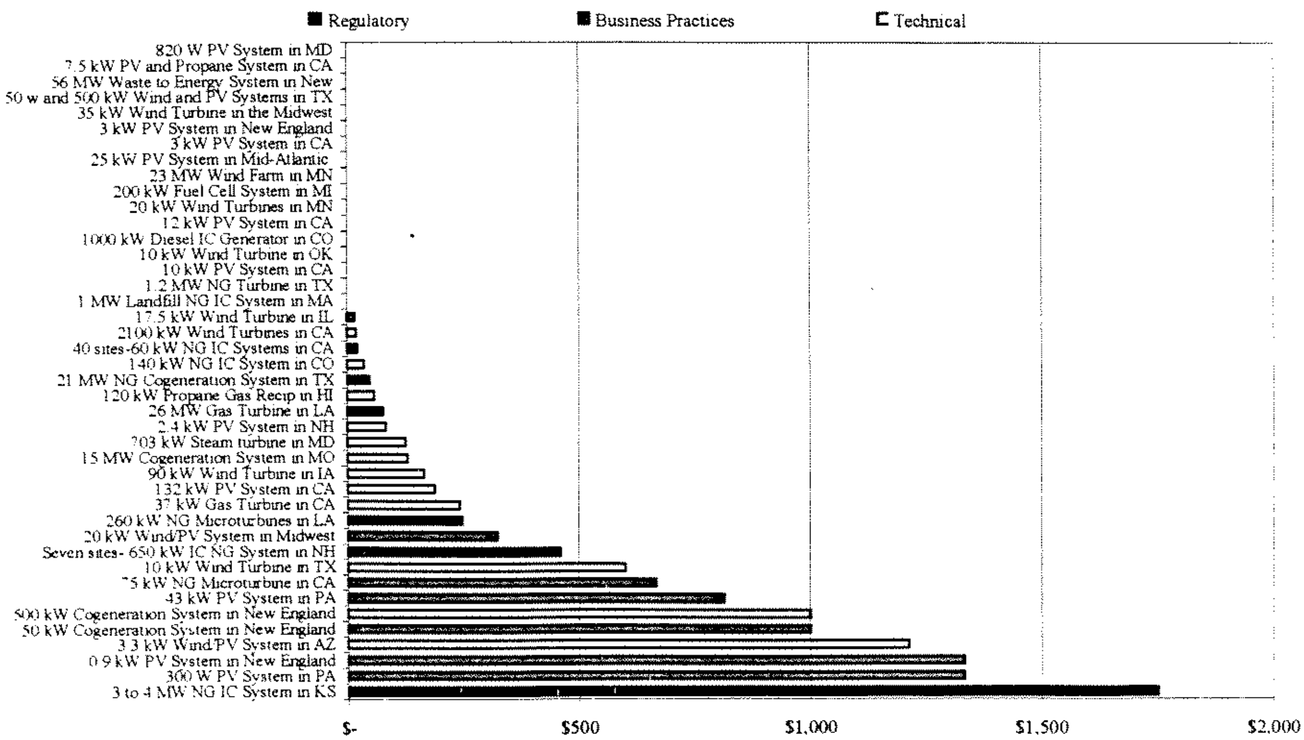
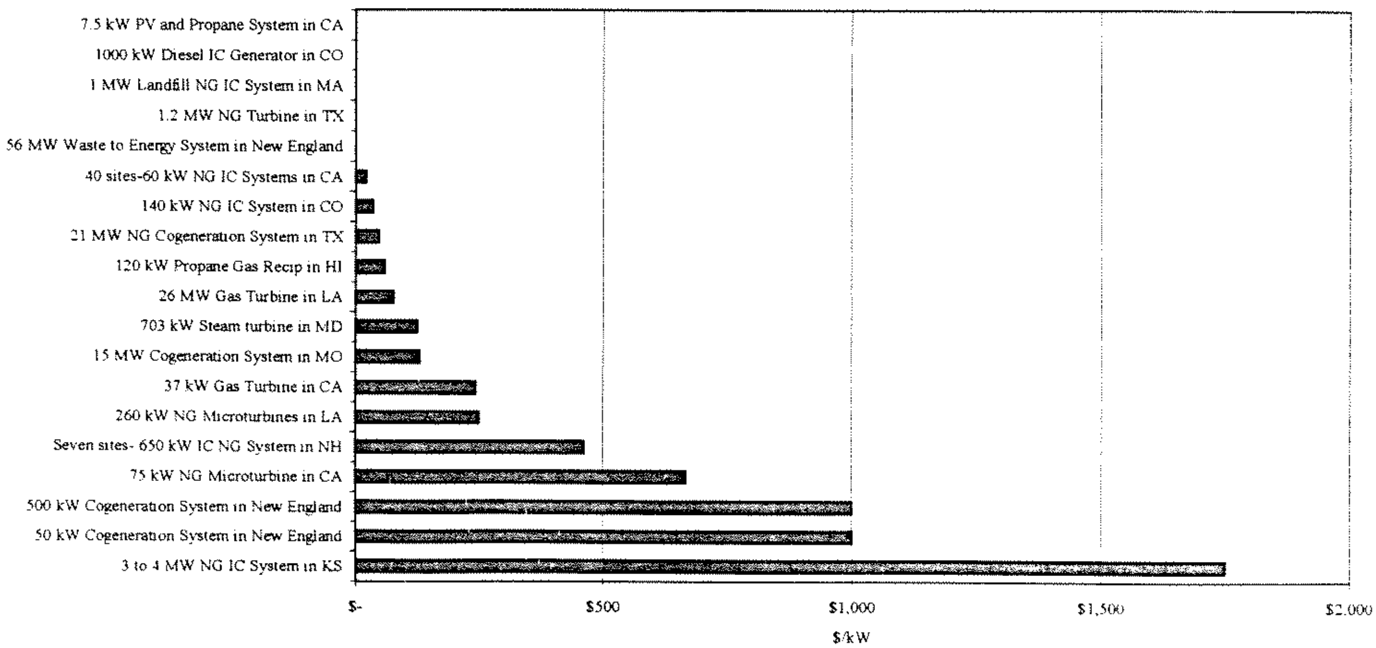


Figure 2-6
Barrier Related Interconnection Costs for Fossil Fuel Projects $/kW



33

A major technical interconnection issue was the requirement for additional protective relays. The inverter equipment already supplied protective relays including ground fault protection relays, under/over voltage protection, and under/over frequency protection. Thus, if there were any kind of fault on either the utility side or the solar site side, the inverter could ensure that the site would automatically shut down.

The utility initially requested installation of additional protective relay equipment that cost between $25,000 and $35,000. This additional protective relay equipment was redundant to the protective relays already provided with the inverter. After negotiations, the utility ultimately agreed that this additional equipment was not needed.

Distributed Generator's Proposed Solutions

The project developer was working closely with the utility to resolve the technical and procedural interconnect issues. The developer was still hoping to negotiate a reasonable solution to the request for redundant relays.

In the project developer's opinion, identifying the right person at the utility was critical and maintaining contact with the individual was also important. If the project developer and the utility had not worked together, the project would have been more difficult and could have been delayed.

Case #14 — 120-kW Propane Gas Reciprocating Engine for Base Load Service at Hospital

Technology/size	Propane Gas Recip Cogen for Absorption Chiller and Hot Water Heating/ 120 kW
Interconnected	No
Major Barrier	Technical—Safety Equipment Business Practices—Discount Tariffs
Barrier-Related Costs	$7,000
Back-up Power Costs	None

Background

A developer was installing a 120-kW propane gas reciprocating engine in a remote area where natural gas was not available and the cost of demand and energy quite high. The project was being installed on the low voltage side of a hospital's own 12.4-kV to 120/2080-volt step-down transformer. This facility was being charged an energy charge of 8.69 cents/kWh and a demand charge of $5.75/kW-month. In addition, because the hospital had a high hot-water bill, it was a good candidate for a cogeneration project. The hospital's monthly electric bill was typically around $12,500/month and the gas bill was $4,700/month. Part of the electric load included chillers that needed to be replaced.
The project was intended to operate as a base load unit. In addition to supplying 120 kW of electric power, the project will also supply hot water to a new absorption chiller and for hot water heating. The project allows for the elimination of a 5-ton heat pump that has been used for heating the swimming pool. With the new installation, the swimming pool can be heated at night when the absorption chiller is not needed. The proposed project will maintain this temperature with only 3 hours of recovered heat a day transferred to the pool.

Technical Barriers

Many of the barriers associated with the project have been technical issues that required resolution between the utility and the developer. The project was scheduled for completion on May 1, 1999. As of September 27, 1999, even though the inspection was complete, the developer had not received a letter from the utility allowing the unit to run for purposes other than testing. These technical barriers include the following:

- The utility requested a lightening arrestor that costs $20,000. The developer is still negotiating with the utility and the issue has not yet been resolved. The lightening arrestor is for the underground 12.4-KV primary voltage line. No other location in the state has this equipment installed at this time.

- The utility requested that a breaker rated for 2000 amps be installed on the low voltage side of the transformer. The building already had 2 separate 1600-amp breakers (for two separate feeders). The equipment specified has not been made since 1982, and GE quoted a cost of $40,000 and six months lead time. This was pointed out to the utility, and the requirement was dropped.

- The utility stated that the high voltage feed was not grounded, and an inspection was required to prove that a high-voltage ground existed. Scheduling the inspection took one month.

The utility requested a reverse power relay, even though this installation is an induction generator that requires an outside source of voltage to operate. The original relay specified by the utility was not appropriate for the installation, and General Electric (supplier of the relay) would not warranty it in the application. The utility agreed to a different relay as specified by General Electric; however, this process took an additional eight weeks. The utility required synchronizing equipment and parallel operation monitoring for the induction generator that has a reverse power relay installed that shuts down the entire cogeneration plant. This cost was over $6,000 for equipment that the developer argued was unneeded.

Regulatory Barriers

Back-up Charges

When the project was proposed, the utility had no standby charges in their tariff. During the project development, the utility requested a $1,200/kW-year standby charge from the PUC. However, the request to the PUC was rejected on the basis that 120 kW could not affect the grid.

Business Practice Barriers

Discount Tariff and Anti-Cogeneration Campaign

The utility has openly discouraged its customers from installing cogeneration facilities and switching to cheaper more-efficient power. In a publication sent to all customers, the utility stated that cogeneration is inefficient and expensive. The publication points out "the heat produced by the cogeneration system cannot be fully utilized by the facility that it serves. Any wasted thermal energy is a lost opportunity for cogeneration units." The publication did not point out that without cogeneration (with the traditional generating station) all the thermal energy is lost.

The utility's publication specifically targeted the addition of absorption chillers to a cogeneration installation. A developer had recently been promoting this technology and had 20 installations in the utility's territory. The publication stated, "The absorption chiller is being added in an attempt to use more of the thermal energy available from the fuel to improve cogeneration system performance. In the past, absorption chillers have not been used because of their very high energy consumption and poor efficiency. For example, a typical absorption chiller requires 1 Btu of energy to create 1-1.2 Btu of cooling. In contrast, a high efficiency electric chiller, such as those qualifying for utility rebates, provides 7 Btu's of cooling energy for every Btu of energy supplied to the chiller." The publication again did not mention that the absorption chiller uses 1 Btu of energy from waste heat that would not be used except in the chiller application. On the other hand, the Btu's used for the electric chiller must be generated by the utility and paid for by the customer.

The utility also stated that the economics of cogeneration were difficult because of the lack of availability of natural gas. Yet, the utility was offering discounts to customers that did not install their own generation source. The utility had introduced a tariff reduction of 11.77 percent for customers who seriously considered cogeneration but opted to stay with the utility. The tariff required the customer to conduct economic analyses showing the savings associated with cogeneration. In addition, the customer must provide cost estimates from vendors showing the cost savings.

At the same time, the utility did have programs to support renewable energy. They had a rebate program for residential solar hot water heaters and an educational program to install photovoltaic systems (PV) in schools. These installations were installed on the customer's side of the meter; thus, the energy generated by the PV project would only be available to the school.

Estimated Costs

The costs associated with this project were primarily associated with the additional equipment required. The additional costs included $7,000 for what the developer believed to be unnecessary equipment and possibly another $20,000, still in negotiation with the utility.

Distributed Generator's Proposed Solutions

In this case, the PUC prohibited the utility from imposing a back-up tariff that would have stopped the project. This case shows that barriers can be removed with regulation. On the other hand, the PUC has also continued to allow incentive tariffs for customers that stayed with the utility instead of installing more efficient cogeneration. (See discussion of economic or uneconomic bypass at notes 44 and 58 on pages 23 and 28.)

The cogeneration plant developer believed that it had met or exceeded all interconnection requirements by the utility, but the utility had not yet allowed the unit to go on line at full output. The plant could operate 95-percent output for testing and documentation. The utility did not provide a schedule when the unit would be allowed to operate.

Case # 15 — 75-kW Natural Gas Microturbine in California

Technology/size	Natural Gas Microturbine/ 75 kW
Interconnected	No
Major Barrier	Regulatory—Utility Prohibition to Interconnection
Barrier-Related Costs	$50,000
Back-up Power Costs	Not Known

Background

In this case, an oil and gas producer with a well located at a public school in California sought to install a 75-kW microturbine and had been unable to interconnect the facility with the local utility under acceptable terms. The principal obstacle was a fundamental disagreement regarding the utility's legal obligation to interconnect a non-utility-owned generating facility, which did not meet the legal definition of a QF under the federal PURPA statute.

The project owner had a producing oil well located on the school property. The well also produced natural gas, which the school had been processing and delivering for sale into a natural gas pipeline. The producer hired a consultant to explore the possibility of capturing additional value from the natural gas by using it to fuel an on-site electric generating facility to power the oil derrick and to use residual heat from the generating facility for space and water heating at the school.

The energy project developer contracted with the school to install a 75-kW microturbine on the school property, in part to allow both the project developer and the manufacturer to gain operational experience with this relatively new product. The project developer planned to operate the facility, with the entire output of the microturbine going directly to meet the oil derrick's electrical loads. Because the derrick's electricity demand of approximately 1,000 kW is larger than the microturbine's 75-kW generating capacity, none of the electricity generated would be delivered to the utility. Assuming that the microturbine was operating at a 95-percent capacity factor, it would produce approximately 52,000 kWh per month, with a value (assuming retail prices of $0.10 per kWh) of approximately $5,200 per month.

The project was installed in July 1999 and operated briefly to ensure operational readiness. The project was then shut down because the project developer had been unable to negotiate an acceptable interconnection agreement with the local utility. As of September 1999, the project remained stalled because no agreement had been reached.

Regulatory Barriers

Utility Prohibition to Interconnection

The project developer stated that recent changes in California law opened the way for the interconnection of non-QF as well as QF generation and that the utility publicly had stated there was "no problem" with interconnecting to the utility. However, the utility refused to interconnect, arguing that it had no legal obligation to do so. The utility interpreted its obligations to interconnect non-utility-owned generating facilities as being limited under the federal PURPA statute to QFs, which included facilities powered by renewable resources such as sun, wind, and water and cogeneration facilities. Because this microturbine did not meet these criteria, the utility's position was that it had no obligation to interconnect the facility to operate in parallel with the utility.

HECO/Maui-DT-IR-43 <u>Ref: COM-T-2, Page 24, Lines 9-13</u>
Mr. Lazar states "Assisting customers with the selection of equipment is little different than providing information on efficient appliances to residential customers - in order for 'competition' to produce an 'efficient' result, customers need access to 'perfect' (or as close as is reasonably achievable) information."

a. Please fully explain what the County of Maui means by "efficient" as used in the statement above.
b. Please fully explain what the County of Maui means by "perfect information" as used in the statement above.

RESPONSE: "Efficient" as used here means appliances which meet or reduce a customers end-use energy requirements at an incremental system cost that is no higher than the next least costly similarly available and reliable alternative. In this sense, a higher capital cost may be offset by a lower fuel, operating, or maintenance cost.

Among the precepts of economic theory is that competition produces an efficient allocation of resources only if certain preconditions are met, including that there are many buyers and sellers, no buyer or seller has market power, there are no barriers to entry or exit, that capital is fungible, and that all buyers and sellers have "perfect information" about the market. The statement is used in this context. In order for customers to be able to compare alternatives, such as utility-supplied energy and DG, they need information on short-run cost, long-run cost, reliability, land requirements, externalities (including on-site noise and vibration, as well as off-site land use and environmental impacts), and other factors. We have learned that absence of objective information on the relative economics of efficiency measures vs. utility-supplied electricity is a barrier to consumer investment in efficiency. Similarly, a lack of objective information on DG may be a barrier (or artificial stimulant) to DG investment.

HECO/Maui-DT-IR-44 Ref: COM-T-2, Page 47, Lines 12-15
Mr. Lazar states "Wind energy is now widely recognized as having a 'capacity credit' to reflect the fact that wind resources often provide peak load relief to the utility. My own research on this topic presented in Docket 7310 showed that a capacity credit approximately equal to the capacity factor of the wind resource was appropriate."

a. Did the PUC make a determination in Docket 7310 as to whether wind energy should receive a "capacity credit"?

RESPONSE: To the best of Mr. Lazar's knowledge, the Commission has not yet issued an Order in this docket.

b. Has the PUC made a determination in dockets subsequent to Docket 7310 as to whether wind energy should receive a "capacity credit"?

RESPONSE: To the best of Mr. Lazar's knowledge, the Commission has not ruled on this issue in subsequent dockets.

HECO/Maui-DT-IR-45 Ref: COM-T-2, Page 70, Lines 10-11

Mr. Lazar states "I have attached Southern California Edison's standby service tariff as Exhibit COM-203, as an example of the form of a relatively progressive standby tariff."

a. Is the County of Maui proposing that MECO implement a standby tariff? If the answer is anything other than an unqualified "yes", please fully explain the response and the basis for the response.

RESPONSE: Yes.

b. Is the County of Maui proposing that MECO use Southern California Edison's standby service tariff verbatim to implement a standby service tariff? If the answer is anything other than an unqualified "yes", please fully explain why Southern California Edison's standby service tariff was attached to COM-T-2 and how the parties to this docket should use the standby service tariff.

RESPONSE: No. It is presented as an example of:

A) A standby rate that imposes a modest demand charge, in recognition that there is customer diversity among DG customers taking standby service, and

B) That it is inappropriate to impose as high a standby demand charge on DG customers as that imposed on full-requirements customers, because the utility need not develop standby capacity equal to the combined load of all DG customers because of that diversity.

HECO/Maui-DT-IR-46 Ref: COM-T-2, Page 79, Lines 3-7
Mr. Lazar states "A detailed service agreement should be required for any standby service. It should extend for multiple years for firm standby service, as the utility must plan and build facilities to serve the probability-weighted service requirements. For best-efforts standby service, where no facilities are being built, a short-term agreement may be reasonable, but it must be unambiguous about the risks to the customer associated with this option."

a. Please quantify how many years Mr. Lazar means when he states "multiple years for firm standby service".

RESPONSE: Enough years to allow the utility to adapt it's resource plan to the unexpected departure of a customer. On a large system like HECO's, it would be fewer than five years, and on a very small system like Lanai or Molokai, it might be ten years or longer.

b. Please quantify how many years Mr. Lazar means when he states "a short-term agreement may be reasonable".

RESPONSE: Less than two years. For "best efforts" standby service the utility need not make any investment in generation or transmission assets, but it might enter into fuel supply or hedging arrangements in anticipation of an expected level of service. The contract might appropriately extend over this hedging period.

RESPONSES TO THE CONSUMER ADVOCATE

CA-IR-44 **Ref: COM T-1, Page 16, Lines 7 through Page 17, Line 14.**

a. Please identify each of the "large commercial back-up generators" referenced on Page 16, Line 13.

RESPONSE: See our response to HECO/Maui-DT-IR-2.

b. To the extent possible, please describe the type of generators for each of these facilities, the firm capacity capability of each generator and the current ability of each generator to be dispatched by MECO.

c. Describe whether the large commercial backup generators could be dispatched for the purpose "to provide reserve capacity to MECO during emergencies" as described on lines 14 through 16 of page 16.

RESPONSE: We expect that the large commercial standby generators could be dispatched automatically by the utility in a manner similar to how these same generators would be dispatched manually by the customer under MECO's proposed capacity buy-back program.

CA-IR-45 **<u>Ref: COM T-2, Page 17, Line 14 through Page 18, Line 5.</u>**

a. How does the deployment of DG relate to the suggestion that "the Commission needs to adopt generation impact fees?" Explain.

RESPONSE: With generation impact fees in place, builders of facilities causing new and increased loads will see an apples-to-apples comparison between the capital costs of on-site generation, energy efficiency options, and purchases of energy from the utility. We believe that cost-effective DG projects will result if builders see the utility's capital costs in choosing the utility-supplied electricity option.

b. Is it recommended that generation impact fees be implemented regardless, and independent of the deployment of DG? Explain.

RESPONSE: Yes. These are desirable to prevent subsidization of growth by existing consumers.

CA-IR-46 **Ref: COM T-2, Page 28, Lines 4 through 13.**

a. Please describe how the two types of standby service, firm and best efforts, would be administered by the utility (i.e., would best efforts standby service be interruptible?)?

RESPONSE: Best efforts standby service would be fully interruptible at any time that provision of that service would cause the utility's spinning and/or operating reserves to fall below levels deemed acceptable.

b. How would standby service be administered by the utility for a customer that "might choose firm standby for a portion of their load, and best efforts standby service for the rest?"

RESPONSE: The customer would be limited to taking their firm standby demand during any period of curtailment. These types of arrangements are quite common for interruptible natural gas customers. A copy of Puget Sound Energy's Schedule 85 tariff, for interruptible gas supply with a firm option, is attached as an example.

See attachment (five pages).

PUGET SOUND ENERGY
SCHEDULE NO. 85
Interruptible Gas Service with Firm Option

Section 1: Availability; Term of Agreement

1. This rate schedule is available in the service area of the company to any nonresidential customer outside of Kittitas County or nonresidential customers in Kittitas County that take no gas service at all during the months of October through March, where customer and company have executed a service agreement for the purchase of interruptible gas service under this schedule and where, in the company's opinion, its facilities and gas supply are adequate to render the required service; provided, however, that interruptible gas service shall not be available to essential agricultural users who, in accordance with Section 401 of the Natural Gas Policy Act of 1978, have requested higher priority of service than that afforded by this rate schedule.

2. Any increase in existing firm or interruptible contract volume is subject to the company's determination of facilities and gas supply being adequate.

3. The term of the agreement between the company and the customer shall be set forth in the service agreement.

Section 2: General Rules and Regulations

Service under this schedule is subject to the rules and regulations contained in the company's tariff and to those prescribed by the Washington Utilities and Transportation Commission and as they may from time to time be legally amended or superseded.

(Continued on Sheet No. 185-A)

ADVICE NO: 2000-17
Issued: November 7, 2000 **Effective:** December 14, 2000
Issued By: Puget Sound Energy

By: __________ Steve Secrist **Title:** Director, Rates & Regulation

PUGET SOUND ENERGY
SCHEDULE NO. 85 (Continued)
Interruptible Gas Service with Firm Option

Section 3: Definitions; Required Volumes

1. Firm use gas. Firm use gas shall be that mutually determined hourly and daily contracted volume of gas set forth in the service agreement, which the company will deliver to customer at all times through the interruptible gas metering facilities, including periods of curtailment of interruptible gas, except as provided for in Section 5 of this tariff. If firm use gas is contracted for, the daily contracted volume shall not be less than two therms per day. The hourly rate of delivery of firm use gas shall not be greater than 1/18th of the firm use per day contracted for or 1/9th of contracted firm use for those customers whose operation is limited to twelve hours per day. Monthly firm use gas shall be the daily contracted volume times the number of days in the billing cycle.

2. Interruptible gas. Interruptible gas shall be all gas used in excess of firm use gas as defined above. The daily contracted volume of interruptible gas shall not be less than 1,000 therms per day.

Section 4: Requirement for Alternate Fuel Capability

The customer agrees to provide and maintain standby facilities of sufficient capacity and a reserve of substitute fuel in sufficient amount to continue operations with a substitute fuel or energy in the event of partial or total curtailment of the interruptible supply. If a customer, on its own petition, has obtained a waiver of the requirements of standby facilities from the Washington Utilities and Transportation Commission, then and only then will the company make service available under this schedule to a customer without standby facilities. If the customer is relieved of maintaining standby facilities and curtails or suspends operations because of a partial or total curtailment of interruptible gas supply, customer agrees and acknowledges that such curtailment of operations results solely from its election not to install and maintain standby facilities and fuel and does not in any way constitute a breach of contract on the part of the company.

(Continued on Sheet No. 185-B)

PUGET SOUND ENERGY
SCHEDULE NO. 85 (Continued)
Interruptible Gas Service with Firm Option

Section 5: Nature of Service; Curtailment

1. The customer agrees that whenever this service is available, customer will use gas under this schedule as the exclusive fuel in those operations and for those purposes set forth in the service agreement between the customer and the company.

2. Gas service supplied on this schedule shall not be interchangeable with any other gas service supplied by the company.

3. Delivery of interruptible gas under this schedule is subject to partial or total curtailment as described in Rule 23 of this tariff.

4. Firm use gas, as defined in Section 3 of this schedule, will not be curtailed except when customer exceeds the contracted hourly or daily rates of delivery or as specified in Rule No. 21 and Rule No. 23 of this tariff.

5. The company shall not be liable for damages occasioned by curtailment or interruption of interruptible or firm use gas service supplied under this schedule.

(Continued on Sheet No. 185-C)

ADVICE NO: 2000-17
Issued: November 7, 2000 **Effective:** December 14, 2000
Issued By: Puget Sound Energy

By: ______________ Steve Secrist **Title:** Director, Rates & Regulation

PUGET SOUND ENERGY
SCHEDULE NO. 85 (Continued)
Interruptible Gas Service with Firm Option

Section 6: Unauthorized Use of Gas

If the Customer fails to comply with the Company's request to partially or totally curtail use of gas in accordance with the conditions set forth in Section 5 of this schedule and in Rule 23 of this tariff, penalties described in Rule 23 will be assessed to the Customer.

Section 7: Rates

1. For purposes of this rate, the measurement of service shall be expressed in therms, one therm being the equivalent of 100,000 British thermal units.

2. Customer charge per month, $300.00

3. The total interruptible gas rate shall be the sum of the total interruptible delivery charges and the gas cost charge.
   a.

Interruptible Delivery Charge	Low Income Program	Total Interruptible Delivery Charge		
9.099¢	0.064¢	9.163¢	Per month per therm for first 25,000 therms	(R)
6.451¢	0.041¢	6.492¢	Per month per therm for next 25,000 therms	(R)
4.951¢	0.027¢	4.978¢	Per month per therm for all over 50,000 therms	(R)

   b. Gas Cost – Interruptible gas cost is: All therms per month multiplied by the sum of the rates in ¢ per therm as shown on Supplemental Schedule No. 101 (Sheet No. 1101) and Supplemental Schedule No. 106.

(Continued on Sheet No. 185-D)

PUGET SOUND ENERGY
SCHEDULE NO. 85 (Continued)
Interruptible Gas Service with Firm Option

4. The total firm gas rate shall be the sum of the demand charges and commodity charge as defined below:
   a. Delivery demand charge: $0.99 per therm per month multiplied by the maximum daily delivery of firm use gas as set forth in the service agreement.
   b. Gas supply demand charge: a rate per therm per month as shown on Supplemental Schedule No. 101 (Sheet No. 1101-B) multiplied by the maximum daily delivery of firm use gas as set forth in the service agreement.
   c. Commodity charge: All firm gas shall be combined with the Customer's interruptible gas and billed at the interruptible gas rates for delivery and gas costs in part 3 herein.

5. Minimum monthly charge:
   a. Minimum monthly therms for the purpose of calculating the minimum monthly charge shall be the greater of:
      (1) fifty percent of the Customer's highest monthly volume in the last twelve months; or
      (2) 15,000 therms.
   b. The minimum monthly charge shall be the sum of:
      (1) the customer charge;
      (2) the firm delivery demand charge;
      (3) the firm gas supply demand charge;
      (4) the total interruptible gas rate applied to all monthly therms delivered; and (T)
      (5) if the monthly therms delivered are less than the minimum monthly therms, the (T) difference of the minimum monthly therms less monthly therms delivered multiplied by the Company's initial block total interruptible delivery charge (Section 7, item 3.a.).
   c. A provision for the suspension of the interruptible portion of the minimum charge for a specified period may be made as part of the service agreement executed by the Company and the Customer.

6. The rates named herein are subject to adjustments as set forth in Schedule No. 1 and other supplemental schedules, when applicable.

Section 8: Payment of Bills

Bills are issued net, are due and payable when rendered, and become past due after fifteen days from date of bill.

CA-IR-46

c. What would the rate structure be and how would the rates be administered for the two types of standby service? Include all workpapers and/or calculations illustrating the derivation of the proposed rate structure, state all assumptions made in the calculations and state the basis for the assumptions.

RESPONSE: The workpapers used to develop the illustrative rates are attached. They show that the "firm" standby rate provides the utility approximately 2 times as much fixed cost coverage per kilowatt as the base full requirements rate, and that the "best effort" standby rate provides the utility approximately 12 times as much fixed cost coverage per kilowatt as the base full requirements rate.

See attachment (three pages).

Base Industrial Rate		Rate	Contribution to Variable Cost	Contribution to Fixed Cost
Demand Charge/ kw		$10.00	$0.00	$10.00
First 200 kwh/kw		$0.10	$0.07	$0.03
Next 200 kwh/kw		$0.08	$0.06	$0.02
Over 400 kwh/kw		$0.07	$0.05	$0.02
Assumed variable cos				
On-peak:		$0.07		
Mid-Peak		$0.06		
Off-peak:		$0.05		

Illustrative Firm Standby Tariff		Rate	Contribution to Variable Cost	Contribution to Fixed Cost
Generation Demand		$3.00	$0.00	$3.00
Transmission Deman		$3.00	$0.00	$3.00
On-Peak		$0.17	$0.07	$0.10
Mid-Peak		$0.12	$0.06	$0.06
Off-Peak		$0.08	$0.05	$0.03

Contribution to System Fixed Cost				
		Full Requirements Customer with 100 kw coincident demand	One Standby Customer with 100 kw non-coincident standby demand	Four Standby Customers with 100 kw probability-weighted coincident Demand
100 kw demand				
500 kwh/kw				
Demand Charge		$1,000		
First Energy Block		$600		
Second Energy Block		$400		
Third Energy Block		$200		
Total Contribution:		**$2,200**		
100 kw generation demand			$300	$1,200
25 kw transmission demand			$300	$1,200
25 hours on-peak @ 100 kw			$250	$1,000
25 hours mid-peak @ 100 kw			$150	$600
50 hours off-peak @ 100 kw			$150	$600
Total Contribution:			$1,150	**$4,600**

Cost coverage Ratio assuming Full Requirements Customer is at cost: **209.09%**

Note: if full receipts were invested in standby capacity, reliability of service would improve for all customers since the capacity acquired would exceed the probability-weighted capacity required.

Discussion of Firm Standby Example.

Assume that there are four customers, each with 100 kw of on-site generation, each of which chooses firm standby service. The utility projects that, on a probability weighted basis, it must have 100 kw of standby capacity in order to achieve the same LOLP for its full-requirements customers with the addition of these four standby customers. With the illustrative rate design, these four standby customers would provide more than twice as much fixed-cost contribution per kw as the full-requirements customers provide. Or, put another way, if the utility invested the fixed cost coverage it receives in actual standby capacity, it would have more standby capacity than it needed, resulting in improved reliability to all customers.

Illustrative Best Efforts Standby Tariff		Rate	Contribution to Variable Cost	Contribution to Fixed Cost
Generation Demand		$1.50	$0.00	$1.50
Transmission Demand		$1.50	$0.00	$1.50
On-Peak		$0.13	$0.07	$0.06
Mid-Peak		$0.10	$0.06	$0.04
Off-Peak		$0.07	$0.05	$0.02

Contribution to System Fixed Cost				

		One Full - Requirements Customer	One Standby Customer with 100 kw non-coincident standby demand	Four Standby Customers with 10 kw probability-weighted coincident Demand
Firm Customer				
10 kw demand;				
400 kwh/kw energy				
Demand Charge		$100		
First Energy Block		$60		
Second Energy Block		$40		
Third Energy Block		$20		
Total Contribution:		**$220**		
Best-Efforts Standby Customrs				
100 kw generation demand			$150	$600
25 kw transmission demand			$150	$600
25 hours on-peak @ 100 kw			$150	$600
25 hours mid-peak @ 100 kw			$100	$400
50 hours off-peak @ 100 kw			$100	$400
Total Contribution:			$650	**$2,600**

Cost coverage Ratio assuming Full Requirements Customer is at cost: **1181.82%**

Note: if full receipts were invested in standby capacity, reliability of service would improve for all customers since the capacity acquired would exceed the probability-weighted capacity required.

Discussion of Best-Efforts Standby Example.

Assume that there are four customers, each with 100 kw of on-site generation, each of which chooses best-efforts standby service. The utility projects that, due to scheduling errors and other factors, that the combined on-peak demand of these four customers (after curtailment) equals 10 kw of peak demand. This implies that the customers are not always curtailed when and as requried by the utility, so they impose a small actual demand on the utility. These customers as a group provide almost 12 times as much fixed-cost coverage to this 10 kw of actual capacity requirement as a full-requirements customer under the illustrative rate design.

CA-IR-46

d. Would standby service continue to be available to customers with DG even after the DG facilities become inoperable? Explain why or why not.

RESPONSE: I suppose this would be possible. However, the margins that are built into the standby rates are larger than those built into the firm service rate, so the customers would prefer to switch to the full-requirements rate. The term of their contracts would need to specify the conditions under which they could do so.

CA-IR-47 **Ref: COM T-2, Page 50, Line 15 through Page 51, Line 10.** The testimony uses the term "virtual power plant" which is described as "a process of knitting together existing customer emergency generators into a viable utility reserve resource to meet extreme conditions."

a. Does the "virtual power plant" essentially involve placing customer-sited emergency generators under the dispatch control of the utility? Explain.

RESPONSE: Yes, subject to pre-emption by the owner for on-site requirements.

b. If customer-sited generation is placed under the direct control of the utility, are the same results achieved without the necessity of creating a "virtual power plant?" Explain.

RESPONSE: No. The utility must make a capital investment under this scenario.

c. Would the utility "provide for the coordination of these units to provide supplemental capacity to the grid" as indicated on lines 19 through 21 of page 50 of the referenced testimony? Explain.

RESPONSE: Yes. The utility would dispatch the plants as needed to provide system reliability.

d. What are the known and estimated number, size and type of existing generators that are considered to be available to provide supplemental capacity to the MECO grid? Also, please identify the source of the information provided in the response.

RESPONSE: The requested information has not been assembled by the County of Maui. See our response to HECO/Maui-DT-IR-2.

e. What is the estimated cost to implement the items referenced at page 51, lines 5 through 10 of the referenced testimony? Please provide copies of all calculations made in determining the estimated cost, state all assumptions, explain why these assumptions are reasonable, and identify the source of the information from which the calculations are based.

RESPONSE: The requested study has not been performed.

f. What is the estimated compensation that would be provided by the utility to the emergency generator owners for use of the existing customer emergency generators to meet MECO system requirements? Please provide copies of all calculations made in determining the estimated cost, state all assumptions, explain why these assumptions are reasonable, and identify the source of the information from which the calculations are based.

RESPONSE: This would be a matter for contractual and/or tariff provisions.

g. Would the compensation be determined based on MECO's marginal, avoided cost determined from MECO's IRP? Explain.

RESPONSE: The compensation would need to be compensatory to the customer, but should be significantly lower than the MECO avoided cost for peaking capacity.

CA-IR-48 **Ref: COM T-2, Page 92, Line 14 through 20.**

a. Please describe the possible size and type of the "renewable generating facility or a combined heat and power facility" that could be developed by Maui County.

RESPONSE: Site-specific analyses have not yet been prepared, in part due to the lack of a suitable institutional framework in which to proceed.

b. Who would own and operate the Maui County generating facility?

RESPONSE: Either the County of Maui or a third-party supplier.

c. What are the number, locations and sizes of the Maui County load that could be served by such a facility developed by Maui County? Provide the source of the information relied to respond to this information request.

RESPONSE: Site-specific analyses have not yet been prepared, in part due to the lack of a suitable institutional framework in which to proceed.

d. Relative to the location of Maui County loads, where would the Maui County generating facility likely be constructed (i.e., customer-sited on location of a particular Maui County load, adjacent or nearby Maui County loads or remotely located from Maui County loads)?

RESPONSE: Site-specific analyses have not yet been prepared.

e. Please identify and describe the "duplicative distribution facilities" that would be placed into service by Maui County absent wheeling by MECO.

RESPONSE: These would be transmission and/or distribution lines between the generating facilities that might be constructed and the locations where the power would be consumed.

f. What is the estimated installed and operating costs of the duplicative distribution facilities referenced at lines 19 through 20? Please provide copies of all calculations made in determining the estimated cost, state all assumptions, explain why these assumptions are reasonable, and identify the source of the information from which the calculations are based.

RESPONSE: Site-specific analyses have not yet been prepared, in part due to the lack of a suitable institutional framework in which to proceed.

RESPONSES TO THE HAWAII RENEWABLE ENERGY ALLIANCE

HREA-COM-T-1-IR-1. On page 16 you propose a DG Demonstration Project as employing the Virtual Power Plant concept by modifying MECO's planned Capacity Buy-Back ("CBB") program. What is your estimate of the potential on Maui for this concept?

RESPONSE: We have not conducted an assessment of the potential for Maui. We would hope that MECO would conduct such an assessment, in partnership with the County of Maui.

HREA-COM-T-1-IR-2. On page 21, you briefly summarize Mr. Lazar's testimony on standby charges (reference also his testimony pages 69 to 79). Are you and Mr. Lazar saying that there are no cases where a DG facility should not have to pay a standby charge?

RESPONSE: Yes. All DG facilities that rely on the system for standby capacity should pay a standby charge.

HREA-COM-T-1-IR-3. As a follow-on to HREA-COM-T-1-IR-2, for a DG facility that is operated continuously (including during peak periods), the DG owner/operator might only want standby service during routine maintenance and emergencies. And, given that the routine maintenance could be scheduled during off-peak times, the actual amount of downtime due to emergencies might average only a few hours a year. Would it be reasonable to assume that the DG owner's load during such downtime could be covered with the utility's operating and/or spinning reserve? If so, the utility would not need to have additional capacity to provide the standby service, and the customer would then pay for only the energy used during the downtime periods. This would seem to be a good trade-off, considering that the DG owner/operator is providing reliable capacity to the grid most of the time.

RESPONSE: No. Any demand placed on the system at any hour reduces the reliability of service as measured by system Loss of Load Probability (LOLP). At a minimum, any standby customer should be charged a sufficient amount to allow for the acquisition of sufficient additional capacity that system LOLP is not impaired, meaning that other customers are not adversely impacted. The workpapers supplied in response to CA IR #5 shows that the illustrative standby rates presented herein meet this test.

RESPONSES TO LIFE OF THE LAND

LOL-WDT-IR-26 Ref: "First, distributed energy resources have very different social and environmental impacts than do conventional utility resources." (COM-T-2: page 12, lines 14-15) "As Mr. Kobayashi discusses, the benefits of distributed generation on Maui are considerable, and the regulatory role of considering these benefits should not be slighted. To the extent that these benefits accrue to the public, not to the utility, it is natural that the utility may be less than enthusiastic to these options." (COM-T-2: page 13, lines 17-20) "What do you mean when you use the term "social cost?" … First, it must truly be a "total" cost analysis - considering not only costs incurred by the utility and the customer, but also costs incurred by the public, the society, or the planet." (COM-T-2: page 30, lines 11-12)

Comments (The following documents were sent electronically to each party)

Job Jolt: The Economic Impacts of Repowering the Midwest: The Clean Energy Development Plan for the Heartland. Regional Economics Applications Laboratory for the Environmental Law & Policy Center. (December 2002);

Economic Impact of Renewable Energy in Pennsylvania. Black & Veatch. (March 2004);

The Potential Economic Impact of Nevada's Renewable Energy Resources. Center for Business and Economic Research at the University of Nevada, Las Vegas (2003);

Importing Energy, Exporting Jobs. U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE);

Sustainable Energy Jobs Report. The Allen Consulting Group. Australia (2003);

Analysis of Renewable Portfolio Standard Options for Hawaii. GDS Associates. Hawaii Department of Business, Economic Development, and Tourism (DBEDT) (2001)

Question: Should economic externalities be evaluated within the IRP process?

RESPONSE: Yes.

(2) Are you familiar with any economic externality study listed above?

RESPONSE: Yes.

(3) What economic externality studies are you familiar with?

RESPONSE: Nevada and the USDOE.

(4) In general, do facilities utilizing local fuel have a greater positive impact on the local economy than importing fuel from outside of the local area?

RESPONSE: Yes.

(5) Please elaborate.

RESPONSE: Use of local fuels avoid payment to off-island providers for fuel. Retaining the fuel payment on-island (or, avoidance of the payment altogether, in the case of wind, solar, or geothermal energy) normally results in a higher ratio of total on-island expenditure of the energy dollar. This is not always the case - for example, a solar PV array with very high installed costs per kilowatt might have a higher off-island capital cost component that the present value of off-island capital and fuel costs for a high-efficiency fossil generating facility. In this situation, even though off-island fuel payments are avoided, the total of off-island payments are higher with solar, and the local economy would suffer.

LOL-WDT-IR-27 Ref: "First, I think the Commission needs to adopt generation impact fees so that new customers see the costs of the energy resources they cause to be developed at the time of construction." (COM-T-2: page 17, lines 14-16)
Question: Should the impact fee consist of two parts: (a) the cost of building the new energy facilities; and (b) an environmental justice fee to pay the community that will suffer through the construction of new central generation facilities and transmission lines?

RESPONSE: No.

Under current ratemaking practices, only the portion of the cost of building new energy facilities not included in tariff rates should be included in the impact fee. A different scheme of ratemaking might exempt customers that pay impact fees from making capital-related payments in tariff rates.

The notion of an "environmental justice fee" is beyond the scope of the testimony.

LOL-WDT-IR-28 Ref: "In general, MECO's current declining block rates that apply to large customers should be replaced with time-of-use rates." (COM-T-2: page 18, lines 15-16)

Question: Should time-of-use rates give greater rewards to those who level their load or to those who switch their load to off-load periods.

RESPONSE: The latter. A "flat" load is relatively undesirable, as it is ALWAYS placing a demand on the system at the time of the system peak. A more desirable load is one that curtails during the priority peak period. The current MECO (and HECO and HELCO) rate designs are flawed, in that the declining block load-factor blocks provide an incentive to remain on the system during peak periods for any customer whose non-coincident peak demand occurs at a different time than the system coincident peak demand.

RESPONSES TO HESS MICROGEN

HESS-DT-IR-1 to COM

Will COM's proposed firm and "best efforts" standby rates create a barrier to the deployment of DG? If no, please explain in detail why not.

RESPONSE: We believe that the proposed standby rates will facilitate DG by providing reasonable cost standby service to customers using DG. This is in contrast to standby rates such as those at HELCO, which fail to recognize the diversity of demand between standby customers, and the reliability benefits of small incremental capacity additions on a system.

HESS-DT-IR-2 to COM   Ref.: COM-T-1, p. 15, lines 10-11.

A. Please explain in more detail what COM means by "reasonable interconnection standards and procedures of DG systems".

RESPONSE: Interconnection standards that are generally accepted within the industry, such as IEEE, and recognize that small DG systems cannot afford high interconnection costs.

B. Please explain in detail how COM's recommended "reasonable interconnection standards and procedures of DG systems" would differ from the HEI Companies standardized physical interconnection requirements and standardized interconnection agreement for DG.

RESPONSE: The requested comparison has not been prepared.

HESS-DT-IR-3 to COM Ref.: COM-T-1, p.21, lines 20-21, "The Commission should consider performance-based ratemaking options to remove the 'throughput incentive' that current regulatory principles provide."

Please explain in detail what COM means by "throughput incentive".

RESPONSE: Current electricity pricing in Hawaii provides for recovery of a margin over variable operating costs in throughput (kilowatt and kilowatt-hour) rates. This means that the loss of sales, under current rate designs, generally causes a loss of short-run profitability to the utility. As our testimony and exhibits demonstrate, in the long-run the opposite is true - increased sales create upward pressure on rates (or, absent rate increases, create downward pressure on earnings). The net effect of this is that the Hawaii utilities will likely be resistant to DG if it reduces sales and profits.

DATED: Wailuku, Maui, Hawaii, August 18, 2004.

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing document were duly served upon the following by electronic mail and by United States mail, postage prepaid, on August 18, 2004, addressed as follows:

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